PETROLEUM RECOVERY INSTITUTE

STUDY OF FINES MIGRATION IN HEAVY OIL RESERVOIRS

BY

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PETROLEUM RECOVERY INSTITUTE

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by:

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EXECUTIVE SUMMARY

A review of the literature on fines migration in porous media was conducted. As a result, various factors which affect fines migration and their relative importance in heavy oil reservoir were identified.

A corrosion resistant linear core displacement apparatus for fines migration experiments was built. The equipment was capable of handling unconsolidated cores (approximately 4 cm in diameter and 15 cm long) high pressures (up to 20 MPa) and high temperatures (up to 250 °C).

Representative core samples from two different heavy oil reservoirs in Alberta were analyzed to determine the type, amount, morphology and location of fines with respect to their pore system. These reservoirs were selected from those with permeability damage problems. Various petrographic tests were conducted on each reservoir core sample, including XRD, and SEM analyses.

A method for extraction of cores, which minimizes the permeability damage in the extraction process was developed. The effects of various parameters including: net confining pressure, velocity, permeability, wettability, viscosity and ionic strength of the injected fluid on permeability damage were examined. The effects of these parameters on permeability damage of various reservoir cores will be discussed in detail in the following sections.

SOMMAIRE

Une revision de la literature concernant la migration des particules fut conduite. Le resultat en fut l'identification de divers facteurs qui influence la migration de particules et leur importance relative sur un reservoir d'huiles lourdes.

Pour etudier la migration des particules, on construisit un appareil de deplacement en milieu poreux, capable de resister a la corrosion. L'equipement etait capable d'utiliser des millieu poreux non consolide (dia. de 4 cm et 15 cm de long), haute pression (jusqu'a 20 MPa) et temperature (jusqu'a 250 deg. C).

On selectionna des echantillons rocheux representatif de deux reservoir d'huiles lourdes de l'Alberta, qui furent ensuite analyses pour determiner le type, montant, morphologie et location des particules en relation a leur systeme poreux. Ces reservoirs furent selectionnes parmi ceux dont la permeabilitee etait endommagee. Plusieurs testes petrographiques furent conduits sur chaque echantillon rocheux, incluant la diffraction des rayons X et microscope electronique.

Une methode d'extraction des echantillons de reservoir, qui minimize les dommages a la permeabilitee, fut developpee. L'influence de parametres divers comprenant: pression de confinement nette, velocite, permeabilitee, mouillabilitee, viscosite et force ionique du fluide injecte sur la permeabilitee endommagee, furent examines. Les effects de ces parametres sur la permeabilitee endommagee de divers echatillons de reservoir sera discute en detail dans les sections qui suivent.

CHAPTER 1

1. INTRODUCTION

Fine particles that can contribute to permeability impairment include clay minerals, quartz, amorphous silica, feldspar, carbonates and barite (1-5). They range in size from much less than one micron up to an arbitrary cut-off point of 30 microns (6), 37 microns (400 mesh) (2,4), 43 microns (325 mesh) (7,8) or 50 microns (9). There is no general agreement as to the definition of "clay fraction" based on grain size. Four microns is commonly considered to be the limiting size (7,9). As the size of clay minerals is small and the structure platey, their surface area is large. Consequently, they tend to react readily and rapidly with fluids introduced into the reservoir. Therefore, clays which are present in oil producing formations play a disproportionately major role in physico-chemical processes involving surface phenomena which lead to formation damage (4,5,7,9,10).

Depending on their origin, two different types of clay are found in oil reservoirs, namely, detrital and authigenic (11,12). Detrital (or allogenic) refers to clay minerals originating outside the rock of which they now constitute a part. Authigenic (or diagenetic) clays are formed either as a direct precipitate from formation waters (neoformation) or through reactions between precursor materials and the contained waters (regeneration). The two different types of clays are shown in Figure 1. For the most part, detrital clays form an integral part of the rock matrix which supports the overburden pressure, and as such are not mobile. However, the authigenic clays can occur as pore linings, pore fillings, replacements, and fracture and vug fillings as shown in Figure 2. Thus, authigenic clays are free to expand or move without causing disaggregation of the rock. Such clays are likely to be mobilized

under certain conditions giving rise to the frequently encountered problem of fines migration with associated permeability reduction. A study of over three thousand sandstone samples have found that authigenic clays are present in most samples (12). Authigenic clays (smectite, kaolinite and chlorite) are abundant and widely distributed in sandstones of divergent compositional and depositional environments in cretaceous sequence of Alberta (11,13). Most heavy oil reservoirs in Alberta are located in this sequence (14).

The authigenic clays which are important to petroleum engineers and geologists may be classified as expanding and non-expanding. Non-expanding clays which are frequently found in oil reservoirs are kaolinite, illite and chlorite. These clays are loosely attached to sand grains and may be easily dislodged by introduced fluids. The loosened clay will migrate and plug pore openings. Expanding clays are montmorillonites and they swell upon contact with incompatible fluids restricting pore openings. Consequently, loss of permeability can be attributed either to clay swelling in the pores, clay particle migration or combination of these two effects (1,15-19). Generally, expanding clay minerals are present in relatively small amounts, and problems from structural expansion is not as widespread as once was thought (20). It is now commonly accepted that fines migration in the form of clays or other fine particles is the major source of permeability damage, even in the presence of swelling clays (1,4,10,20-25). However, the swelling of clays is an important mechanism for dislodging fines and starting migration.

As clay minerals are the major contributors to the phenomenon of fines migration, it is necessary to look at the structure and various properties of clays.

CHAPTER 2

2. CLAY MINERALS

2.1. STRUCTURAL ASPECTS

Although the clay minerals are quite minute, they are crystalline solids. The principal building elements of the clay minerals are two-dimensional arrays of silicon-oxygen tetrahedral (silica) and two-dimensional arrays of aluminum or magnesium-oxygen-hydroxyl octahedra (alumina or magnesia) (26-28). The majority of clay minerals belong to the class of layer silicates or phyllosilicates because their structural framework is basically composed of layers comprising silica and alumina sheets, joined together in varying proportions and stacked on top of each other in a certain way. A schematic representation of a silica tetrahedral sheet and an alumina octahedral sheet is shown in Figure 3.

The condensation in a 1:1 ratio of a silica sheet with an alumina sheet gives rise to a two-sheet mineral as in kaolinite (Figure 4). In a three-sheet mineral, two silica sheets condense with an alumina sheet. The resultant layer structure is such that the alumina sheet is sandwiched between two sheets of inward-pointing, linked silica tetrahedra, as exemplified by pyrophyllite (Figure 5). The combination of an octahedral sheet and one or two tetrahedral sheets is called a unit layer. The distance between a certain plane in the unit layer and the corresponding plane in the next unit layer is called the d(001) or basal spacing. This distance is shown in Figures 4 and 5.

The type of cation occupying tetrahedral and octahedral sites is limited more by ionic size and coordination number than by valency (27). Hence, there, is considerable scope for isomorphous replacement or substitution in

these structures. A common situation is the partial substitution of Si^{4+} in tetrahedral and octahedral sites, respectively, for cations of similar size and coordination number but of lower valency. Such a process gives rise to structures with a permanent negative charge. For example, when pyrophyllite (Figure 5) goes through partial substitution of Al^{3+} for other cations (e.g. Mg^{2+}, Fe^{2+}) in octahedral sites and, less frequently, of Si^{4+} for Al^{3+} in the tetrahedral sheet, montmorillonite is formed (Figure 6). In addition to isomorphous substitution, lattice imperfections may also contribute to the negative charge on the surfaces of clay minerals. For instance, the absence of a constituent metal atom from its place in the clay structure, dislocations, and localized bond breakages would result in a negative charge on the lattice (28).

The flat unit layer surfaces are not the only surfaces of plate like clay particles, they also expose an edge surface area. At the edges of plates, the tetrahedral silica sheets and the octahedral alumina sheets are disrupted, and bonds broken. It is widely recognized that edges of clay particles are positively charged in the neutral and acidic pH ranges due to adsorption of potential-determining ions. The point of zero charge does not necessarily occur at neutral solutions (pH=7) (26). The presence of oppositely charged edges and faces on clay particles leads to considerable edge-to-face flocculation in aqueous suspensions.

The stack of unit layers of clays are held together by interlayer hydrogen bonding, van der Waals forces and interlayer attraction of electrostatic origin (26,27). However, these forces are comparatively weak with respect to the primary valence forces which hold the atoms in the unit layer together. Consequently, cleavage parallel to the unit layers is easy.

Moreover, depending on the strength of the interlayer bonding, some clay crystals can also exhibit interlayer expansion or swelling. For instance, members of kaolinite group which are two-layer clays and illites which are three-layer clays do not expand due to strong interlayer forces. On the other hand, smectites (montmorillonite) which are three-layer clays, swell in water because interlayer forces are weak.

2.2. ELECTRICAL PROPERTIES

The net negative charge on clay particle surfaces attracts counter-ions (cations) from the solution while repelling ions of the like sign (anions). The compensating cations have a tendency to diffuse away from the surface since their concentration will be lower in the bulk solution. At the same time, they are attracted electrostatically to the charged lattice. The result of these opposing trends is the creation of atmospheric distribution of the compensating cations in a diffuse layer on the exterior layer surfaces of clays. Hence an "electrical double layer" is formed which is made up of the negative surface charge and the balancing cation charge (Figure 7). The compensating cations in the double layer can be exchanged for other species of ions of the same sign if they are made available in the solution. The total amount of exchangeable cations may be determined analytically and is expressed as the number of milliequivalents of the ion per 100 g dry clay. The cation exchange capacity of clays frequently found in petroleum reservoirs is shown in Table 1.

As the surface charge arises from isomorphous substitution and lattice imperfections within the structural network, clay colloids are of the "constant charge" type as distinct from the "constant potential" kind. The counter-ion atmosphere is generally referred to as " Gouy-Chapman" layer and

the exact distribution of positive and negative ions as a function of distance from the surface can be calculated from the Gouy-Chapman theory (27,29). Application of this theory yields the following expression for the decay of potential ψ with distance x, which is approximately an exponential decay:

$$\frac{d^2u}{dx^2} = K \sinh u \qquad (1)$$

where;

$$u = \frac{\nu e_o \psi}{k T} \qquad (2)$$

and;

$$K = \frac{8 \pi \nu^2 e_o N_A C_o}{\varepsilon k T} \qquad (3)$$

The term $1/K$ is called the Debye length and is a measure of the thickness or extension into the medium of electrical double layer.

A major limitation of Gouy-Chapman theory is that Equation 1 neglects the finite size of ions and thus ignores the fact that ion centers can approach no closer to the interface than the ionic radius. A first approximation to account for this effect involves dividing the double layer into two parts: a "compact" or "Stern" layer adjacent to the interface which is devoid of ions and which has a thickness, δ, of the order of the molecular dimensions, and a "diffuse" layer or Gouy-Chapman layer which extends into the bulk solution. The potential decay in the Stern layer falls off linearly from its surface value (ψ_o) to the so-called Stern potential (ψ_δ). Beyond the Stern layer, the potential decay follows Gouy-Chapman theory. A further refinement is the existence of an outer "Helmholtz" layer which is thought to lie just outside the Stern layer marking the boundary between the fixed and mobile part of the

diffuse double layer (plane of shear or slipping plane). At this plane, the potential is zeta (ζ), being the only potential which is experimentally accessible. In practice, however, it is frequently assumed that $\zeta = \psi_\delta$. Figure 8 illustrates these concepts.

It is useful to express Equation 3 in terms of the ionic strength, I, which is given by:

$$I = \frac{\sum C \nu^2}{2} \tag{4}$$

For aqueous systems at room temperature, the double layer thickness can be approximated by:

$$\frac{1}{K} = 0.3\ I^{0.5} \tag{5}$$

indicating that as the ionic strength of the systems increases, the double layer becomes more compressed or thinner.

2.3. INTERACTION OF FORCES

2.3.1. Attractive Forces

When two clay particles approach each other, attractive forces between particles favour flocculation. The chief source of attraction between molecules are the van der Waals forces. These forces stem from induced dipole-induced dipole interactions. That is, a dipole which develops transiently in one molecule as a result of continual motion of its electrons induces a dipole in the second molecule. Although the time averaged dipole moments are zero, the time averaged interaction energy is not. This potential energy per unit area of interaction between two clay particles is given by

(29):

$$V_A = - \frac{A_H}{12 \pi h^2} \qquad (6)$$

Where the Hamaker constant, A_H, is a key parameter characterizing the strength of the attractive forces. The total attraction potential will depend on the particle size, that is, attractive forces for larger particles are greater (see Figure 9).

2.3.2. Electrical Double Layer Repulsion

When clay particles are close to each other, their diffuse counter-ion atmospheres begin to interact. It can be shown that this interference leads to changes in the distributions of the ions in the double layer of both particles, which involves an increase in the free energy of the system. Work must therefore be performed to bring about those changes; in other words, there will be repulsion between particles. A simple form of the repulsion energy between two clay particles is given by (29):

$$V_R = \frac{64 N_A C_o K T}{K} \gamma^2 \exp(-Kh) \qquad (7)$$

In Figure 10, three potential curves are shown which are valid for the same particles but for different electrolyte concentrations.

2.3.3. Total Interaction Energy

The net or total interaction energy (V_T) between clay particles can be found by combining van der Waals attractive forces and the repulsive forces produced by double layer repulsion. This concept is the basis of "DLVO"

theory (29). To find the total interaction energy between two particles, the contributions from attractive and electrical effects are simply added. A schematic representation of total interaction energy as a function of separation distance is shown in Figure 11. In constructing the curve of net interaction, an additional interaction force should also be taken into account (26). This is a repulsion of very short range to which there are two possible contributions. One, the Born repulsion which arises due to the overlap of the atomic electron orbitals of the two interacting particles. A second short range repulsion is the result of specific adsorption forces between the crystal lattice and the molecules of the liquid medium, i.e. water. Owing to such adsorption forces, usually one or two monomolecular layers of water are held tightly by the particle surface. The work required for the desorption of this water manifests itself as a short range repulsion between particles. The increasing importance of the short range repulsion for the net interaction is observed by the steep rise of the potential curve at very small values for the particle separation. Thus, there is a theoretical limit to the distance of closest approach of two bodies. At separation distances below about 30A°, above-mentioned forces and "hydration forces" sometimes cause large deviations from the predictions of DLVO theory. Hydration forces are oscillatory forces associated with the ease of packing molecules between two surfaces (29,30).

It is possible to understand how clay particles react with one another by inspecting Figure 11. In the first place, the total interaction energy (V_T) becomes large and negative for decreasing values of separation (h). Attractive forces dominate in this region as a brief inspection of Equations 6 and 7 indicates. The curve must eventually reach a minimum since short range repulsive forces which come into play when particles are virtually in contact

will cause V_T to become positive again. The existence of this "primary" minimum shows that the particles will adhere to one another (flocculate) if they can ever be brought sufficiently close together. At somewhat larger values of separation, the curve in Figure 11 exhibits a maximum. This maximum may be considered as an energy barrier which must be surmounted as particles approach each other if they are to adhere.

Another feature of Figure 11 is a shallow "secondary" minimum at separation distances somewhat larger than that of the maximum. The secondary minimum occurs because V_R falls off more rapidly with increasing distances than does V_A.

Figure 12 illustrates the effect of varying the Hamaker constant, A_H. As would be expected, increasing A_H lowers the height of the energy barrier. Figure 13 shows the dramatic changes caused by varying electrolyte concentration, (K, in ppm) and hence the Debye length, $1/K$. Adding electrolyte decreases the Debye length (see Equation 5) and hence double-layer thickness with the result that electrical forces do not become significant until particles are closer together. When they finally do become important, attractive interaction is greater and the height of the energy barrier is less. Adding sufficient electrolyte removes the maximum altogether, as Figure 13 shows.

Curves of this type provide a basic understanding of the colloid stability of clays. Attractive forces favour flocculation and oppose dispersion while electrical repulsion has the opposite effect. Flocculation occurs if particles can reach the separation corresponding to the primary minimum. The single most important factor influencing flocculation is the height of the maximum in the V_T curve. If it is nonexistent or small,

particles have little trouble reaching the primary minimum as a result of ordinary thermal motion and clays will be stable. But if the maximum is sufficiently high (several times the energy of thermal motion, kT) particles almost never have sufficient energy to surmount this energy barrier and they usually stay destabilized. The qualifying word "usually" is needed because flocculation can occur, in principle, at separations corresponding to the secondary minimum. Such flocs cannot persist, however, unless the depth of the secondary minimum is several times kT. This condition is usually not satisfied with the result that no flocculation takes place even though the V_T curve has a secondary minimum.

The Brownian motion is not the only mechanism by which one particle can come into contact with another. There can be convection in the system as well. Convection aids flocculation when it enhances the relative velocity between nearby particles, making it easier to overcome the energy barrier and reach the primary minimum corresponding to flocculation. Application of hydrodynamic shear is especially effective in flocculation of relatively large particles (29). It can also break up flocs associated with the secondary minimum of the particle interaction curve. However, it has been shown that the total energy diagram is relatively unaffected by hydrodynamic inter-actions, at fluid velocities commonly encountered in oil reservoirs (5,31).

Several general conclusions can be drawn concerning clay stability. Larger particles are more likely to flocculate as attractive forces are greater (Figure 9). Reducing the magnitude of the surface potential by adjusting the concentration of the potential-determining ion in solution also promotes flocculation. Finally, adding an electrolyte strongly promotes

flocculation (Figure 13).

Clay minerals are not the only components of clay-sized materials (<4 μm) which have cation exchange capacity. All inorganic minerals of extreme fineness also have a small cation exchange capacity, as a result of broken bonds around their edges (9). That is, an electrical double layer exists around these fine inorganic particles. These materials include silica fines and silt. Moreover, detrital grains which form pore surfaces and consist primarily of mineral oxides acquire their surface charges by adsorption of potential-determining ions from the interstitial brine. The surface charge varies from a positive value at low pH to negative at high pH (5).

CHAPTER 3

3. FINES MIGRATION IN OIL RESERVOIRS

The clay minerals found in petroleum reservoirs are in an agglomerated or flocculated state. If the introduction of foreign fluids causes deflocculation or dispersion of clay particles, permeability may be impaired due to migration of dispersed particles. In all clay-water systems, there are certain factors which tend to keep clay particles in a flocculated state and certain other factors which tend to disperse them. The relative combined strength of opposing factors determine whether the particles will disperse or hold together. Any fluid flowing through a formation will cause permeability damage if the contribution of clay dispersing factors exceed the contribution from binding factors.

The factors contributing to binding of clay particles in compact, oriented aggregations include (32-34): (1) van der Waals forces; (2) recrystallization and chemical alterations; (3) sorption of organic matter from oil; (4) mutual sorption of ions between adjacent unit layers; (5) electrostatical attractions between positively charged edges (pH<7) and negatively charged faces; and (6) a thermodynamic drive to reduce interfacial energy by reducing surface area. The factors which contribute to swelling and dispersion of clay particles include (32-34): (1) hydration of exchangeable cations, (2) hydration of particle surfaces, (3) Born repulsion forces, (4) repulsion of double layers, (5) desorption or chemical removal of sorbed binding matter, (6) neutralization of positive edge charges, (7) hydrodynamic shear, and (8) Brownian (thermal) motions.

Fines migration phenomenon can be examined from two distinct

perspectives: mechanical aspects and chemical aspects (33,35,36). The major factors which affect mechanical fines migration are: flow rate, viscosity, core length, particle and pore size distributions, formation properties and existence of another phase. The major factors which affect chemical fines migration are: ionic strength (salt concentration), temperature, rate of change of various parameters, pH and extraction process. In addition to these two damage mechanisms, geochemical transformations may cause permeability reduction as well (35,37). Formation damage through geochemical transformations such as dissolution, precipitation, and chemical reaction occurs usually during thermal recovery processes or carbon dioxide injection.

As was pointed out, fines migration is affected by both mechanical (physical) and chemical parameters. Comparison of the effects of mechanical parameters can only be made if the effects of chemical parameters are constant. Similarly, analyses of the effects of chemical parameters can be facilitated only if mechanical parameters are constant.

3.1. MECHANICAL FINES MIGRATION

Permeability loss by mechanical fines migration occurs when loosely attached particles are mobilized due to mechanical forces created by flowing fluids. If these particles are dispersed in sufficient quantities, they can be lodged at pore constrictions and reduce the permeability of the formation. The effect of different variables on mechanical fines migration will be discussed next.

3.1.1. Flow rate

It has been recognized generally that fines migration and resulting

formation damage is a rate-sensitive phenomenon. In particular, it has been shown that the flow of a chemically compatible fluid (brine) causes permeability reduction if the velocity is above a critical value (33,35,38-41). This is thought to be caused by the following phenomenon (24,38,40). At low rates, dispersed fines can gradually align themselves to work their way one by one through the pore constrictions. At high rates, the randomly distributed fines in rapid motion interfere with each other and bridge in a "brush-heap", or edge-to-surface (42), structure. These bridging and non-bridging conditions are illustrated in Figure 14 and the resulting permeability decline is shown in Figure 15.

More insight into the mechanism of permeability damage can be gained if one considers channel flows. Experience with channel flows shows that in channels where fluids is accelerating, velocity profiles tend to become more uniform and there is less tendency to develop eddies. The opposite is true for decelerating flow (43). Hence, we may assume that the flow in a pore approaching a constriction over the front face of a sand grain has a tendency to have more uniform velocity profiles, while the flow away from the constriction will tend to accentuate the differences in velocity profile and to form eddies if flow rates are high enough (44). The result will be formation of brush-heaps. However, one study claims that core permeability is not reduced even at a flow rate three orders of magnitude higher than typical field velocity (1 ft/D) if the flowing fluid is compatible with clays (23).

One of the characteristics of fines migration damage is the increase in permeability when the flow direction is reversed (23,33,35,39,40,41). Permeability behavior of this type is known as "check valve" plugging (23). This phenomenon is illustrated in Figure 16 and explained as follows: fines

that are mobilized during brine injection lodge at pore constrictions and form bridges, but, when the flow is reversed, an instantaneous increase in permeability occurs because the particle bridges are destroyed. However, the permeability rapidly declines again because new particle bridges are easily formed due to high velocity and high particle concentration. The permeability damage does not recur as long as the velocity is maintained below its critical value, V_c, when the flow is reversed.

The constant permeability decline indicates that more and more particle bridges are formed as the flow continues. However, a lower limit for the permeability reductions should be reached. This is because, particles which form bridges reduce the cross section of the pores, but due to the maintenance of the flow rate, the fluid velocity in pores increases. Finally, a balance point is reached where a non-retaining porous medium is formed and any more particles which are mobilized are carried out in the effluent (45). Some other factors may contribute to the mechanism of pore throat blocking at high flow rates described above. One of these factors is the particle concentration. It has been shown that the degree of plugging in porous media is also a function of particle concentration (2,40,46). Another factor is the stability of the particle bridges or brush-heap structures at various rates. Visual observations in a micro-model revealed that bridges formed at high flow rates are tightly packed and quite stable; conversely, bridges formed at low flow rates are very unstable and weak (2). Therefore these two factors may aid in reducing permeability at high flow velocities. That is, at non-damaging velocities, particles are either not mobilized in sufficient concentrations to cause pore throat bridging or else particle bridges are not tight enough to affect microscopic change in permeability. At damaging

velocities, particle concentrations are high enough and/or particle bridges tight enough so that a loss of permeability is observed (33,47).

The studies of suspension flow through porous media are not directly applicable to fines dispersion and migration because in suspension flow, a distinction has to be made between pressure drop across any filter cake that may form at the interface and across the core. However, this type of behavior is important in processes where fines in the injected fluids may cause permeability damage. These type of studies have found that higher flow rates cause less damage (45,40,49).

Most heavy oil reservoirs are found in unconsolidated sands. Generally, less indurated (unconsolidated or semiconsolidated) formations are more susceptible to rate damage (37). Therefore, one must be very careful when dealing with a heavy oil reservoir, because serious damage can occur due to high flow rates.

As fines migration is rate sensitive, for every reservoir rock, there is a critical (threshold) volumetric flow rate beyond which particle movement becomes a pore-plugging problem (40). However, insufficient data are available about the actual threshold rates where clay or other fines begin to detach and migrate in water-sensitive formations (37,38). Factors which affect rate damage appear to be dependent upon formation, fines and fluid characteristics. Thus, it may always be necessary to rely on laboratory experiments to estimate critical rates.

3.1.2. Viscosity

The mechanical instability of clays and other fines is partly due to the shear stress created at the pore walls by flowing liquids (41,50). When the

binding force that holds the particle on the pore surface is exceeded by the viscous drag force, the particle is dislodged (39). That is, the viscous drag or hydrodynamic shear may trigger the release of weakly bonded clays, mica, feldspar, and other minerals. The released particles will be entrained by the flowing fluid and bridge at the pore constrictions.

The viscosity of the flowing fluid is one of the factors which determine the amount of viscous drag on fine particles. In particular, it will be easier to entrain fine particles if the flowing fluid is more viscous. To the author's knowledge, the effect of viscosity on fines migration has only been investigated in one study (39). The results obtained by this study are shown in Figure 18; as expected, higher viscosity fluids have lower threshold (critical) rates.

3.1.3. Multiphase Flow

Most experimental and theoretical studies of fines migration in porous media investigate single phase flow systems. This is because of the complexity of the problem even with single phase flow. However, fines migration occurs in the presence of oil, water and gas under actual field conditions. Therefore, it is important to consider the effect of the presence of a second phase in studying the fines migration phenomenon.

Early studies of formation damage showed that the presence of residual oil in the core can act as a deterrent to permeability reduction by fresh water flow (18). In addition, it has been observed that although the permeability may be damaged during the flow of fresh water or brine, some of the damage can be restored by injecting oil subsequently, especially if there are little or no swelling clays in the rock (15,51).

A detailed micromodel study has concluded that when immiscible fluid phases are present in pore spaces, wettability of the particles and the relative amounts of fluids flowing through the pores influence particle movement strongly (2). It has been observed that fines are mobilized as long as the fluid which wets them is mobile. Therefore, if fines are water wet, flow of oil at connate water saturation restricts their movement within the connate water film (Figure 19). If fines have mixed wettability, their movement is confined to the oil-water interface (Figure 20). As long as both oil and water are flowing, considerable fines movement occurs because of the localized pressure disturbances caused by oil-water interfaces travelling through the pores (Figure 21).

There have been some conflicting results as to the effect of multiphase flow on the existence of a critical velocity. One study concluded that no critical velocity exists for the flow of a chemically compatible, non-wetting fluid (oil) at connate water saturation (33). This result seems to agree with the observations of fines migration in micromodels. That is, at all flow velocities of a non-wetting fluid, particle confinement in the connate water film precludes particle migration and plugging. However, another study has observed that oil flow at connate water saturation increases the critical velocity to higher values than that obtained during single phase flow (39). The contradiction in these observations may be partly due to the wettability of fines in the cores used. In other words, if some of the fines are oil wet, they may be entrained by flowing oil and plug the pore constrictions at high velocities. Nevertheless, more research is needed to investigate this phenomenon in detail.

Another micromodel study investigated fines migration in the presence of

gas and water (52). It was found that fines arriving at the gas-liquid interface adhere to the bubble. At low flow rates, gas bubbles together with adhering fines may form a barrier to flow. However, if the flow rate is. high enough, the moving bubbles will also enhance the rate of fines transport. The finding that movement of fines is strongly affected by interfacial forces has important implications for secondary or tertiary recovery processes in which chemicals are injected into the formation. If the injected chemicals change the interfacial properties between oil, water and gas present in the reservoir, appreciable fines movement may occur. The effect of changes in interfacial forces on fines migration needs further investigation to determine the resulting formation damage during secondary and tertiary recovery operations.

3.1.4. Particle and Pore Size

It has been stated that the relationship between the particle size distribution and the pore size distribution plays a large role in mechanical pore throat bridging (40,53,54). Studies of the flow of particle suspensions through porous media and deep bed filtration have shown that the ratio of grain size to particle size effects the removal efficiency of these particles in the porous medium (6,53-60). Experiments indicate that selected particle size distributions can be transported through porous media with given pore size distributions with minimum damage to porosity or permeability (57,58). That is, there exists a particle size for which removal efficiency (and thus, filter coefficient) is minimum in a given porous medium (6,59,60). For particle sizes larger than this size, removal efficiency increases and is accomplished by sedimentation and straining. For smaller particles removal

efficiency increases due to increased Brownian diffusion (55,56). This phenomenon is illustrated in Figure 22 for three different velocities.

The results mentioned above can be applied to the problem of formation damage by clays. That is, once clays are dispersed the plugging of the pore constrictions will be controlled by the ratio of particle diameter to the pore throat diameter. At a certain ratio of average particle to pore throat size, a maximum number of particles will be transported through the porous medium and eluted. Any other ratio below or above this size ratio will cause increased capturing of particles and result in permeability reduction.

3.1.5. Formation Properties

The degree of mechanical fines migration damage may also depend upon the properties of the particular formation under consideration. Two of these properties, pore size distribution and wettability, has already been mentioned in the previous sections. Other formation properties which affect fines migration are the permeability of the rock and the location of clays with respect to pores.

The extent of permeability damage is to some degree related to the absolute unreduced permeability of the rock (26,33,42,61,62). Experiments carried out in Berea sandstone cores which are known to contain non-swelling clays revealed that when distilled water follows brine flow, more permeable cores did not plug completely, but expelled a considerable amount of migratory fines in the effluent (61). A formation with high permeability is less susceptible to damage by mechanical mobilization as more permeable rocks have probably larger pores and pore throats. However, such high permeability rocks may be damaged more easily by swelling clays. On the other hand, a tight formation may be more affected by migrating particles than by swelling

particles. A more common case is the damage caused by a combination of migrating and swelling particles.

Another formation property which is important in mechanical fines migration is the distribution and location of clay particles within the pores (37,63). Total clay content, or clay type, is not always a dependable means to classify susceptibility to damage. That is, the effect of clays on fluid flow is not always proportional to the clay mineral content of the rock and quantitative determinations of clay mineralogy by X-Ray Diffraction alone may not be particularly useful in predicting permeability damage. The location of the clays in the pores and morphology (clay growth form) tend to control the degree of fluid sensitivity in most reservoirs.

3.1.6. Length of Porous Medium

In deep bed filtration processes where a suspension of particulate matter flows through a packed, porous bed, it has been found that higher filtration efficiency is attained. if the bed is longer (44,64). Similar results were obtained when fines migration experiments were conducted in consolidated cores (17,23). That is, the degree of permeability damage also depends on the length of the sample.

Results of one suite of experiments are shown in Figure 23. It is seen that for these sandstone cores, maximum sensitivity is attained in less than 1 inch. This is probably due to the fact that in shorter cores, the number of constrictionless pores is greater, and as a result, a higher percentage of the dispersed material is washed out rather than lodging and impeding flow. However in a longer core, there is more opportunity for trapping dispersed clay particles. Therefore, the reduction in core permeability is less in a

shorter core compared with that in a longer core.

It is seen in Figure 23 that the effect of length on permeability damage diminishes after a short length and maximum damage is reached. Therefore, the length dependency effect is probably of more importance in the laboratory than in field applications.

3.2. CHEMICAL FINES MIGRATION

Permeability reduction by chemically-initiated fines migration is observed when a chemically incompatible fluid is introduced into the porous medium causing chemical interactions which promote release of the fines. These chemical interactions alter the balance between forces which are binding and forces which are dispersive. Consequently, clays expand, disperse, migrate and plug the pores resulting in a permeability decline. Next, the effect of different factors on chemical fines migration will be reviewed.

3.2.1. Salt Concentration (Ionic Strength)

It was pointed out in sections II. B. (Equation 5) and II. C. 3. (Figure 13) that electrolyte concentration has a very big impact on the total energy of clay particles. That is, higher electrolyte concentrations tend to compress the double layer, decreasing the electrical repulsion between the particles. Therefore, the exchangeable cation atmospheres will be diffuse in distilled water and compressed in high concentration of electrolyte. In distilled water, they will be more diffuse if the ions are monovalent than if they are divalent (see Equations 4 and 5).

The results of a typical water shock experiment is shown in Figure 24. The normalized permeability decreases by two orders of magnitude after only two or three pore volumes of fresh water have been injected. This is due to

the blocking of pore throats by clay particles released from pore walls as a result of increased double layer repulsion. The primary reason for dispersion of clays is the hydrolysis of sodium cations which are adsorbed between crystal faces (19). When the flowing solution is changed from NaCl to fresh water, the ions in the diffuse double layer Na^+ and primarily Cl^-, are washed away and removed by flowing distilled water leaving only Na on the surfaces of clay crystals. These cations are held in the exchange sites. Having no double layer around them, they readily hydrolyze, causing an expansion between crystal faces weakening the attractive forces. These particles now readily disperse with shear forces created by the flowing fluid.

3.2.1.1. Critical Salt Concentration

A similar phenomenon occurs if the concentration of the salt drops below a critical value so that electrical double layer repulsion is significant (23, 65,66) (see Figure 25). The salt concentration at which clays start to disperse, migrate and lodge at pore constrictions is called the Critical Salt Concentration (CSC) (23,25,46,65). For the system shown in Figure 25, the total interaction energy for various concentrations of NaCl has been calculated and plotted in Figure 26 as a function of distance of separation (34). One observes that above a salt concentration of 0.072 M, the particle pore-wall attachment is in attractive state and no release is expected. This agrees with the results reported in Figure 25. When the solution concentration is reduced below 0.072 M, the detachment of particles should take place as the double layer repulsive forces become dominant. In the limiting case, when the flowing fluid is pure water, a significant release of particles is expected to occur which explains the behavior in Figure 24. It

has been experimentally shown that in the range of superficial velocities from 3.2 to 570 cm/hr, the CSC was independent of the flow rate (65).

It has been observed that when the salt concentration drops below CSC, the concentration of clay particles in the effluent goes through a maximum and then decreases (46,66). This means that at any given concentration below CSC, a certain number of clay particles are released. Some of these particles are eluted from the core and detected in the effluent and others are deposited at the pore constrictions. Once all mobilized particles are either expelled or deposited, particle concentration in the effluent goes back to background levels again.

3.2.1.2. Valence of Cation

The charge or valency of a cation was found to have a dramatic effect on the CSC. In fact, it has been observed that the phenomenon of water sensitivity does not occur when divalent salts such as $CaCl_2$ are used instead of monovalent salts (15,19,32,34,65). Figure 27 shows the results of shock experiments for the same concentration of different salt solutions. It can be observed that there are almost no reductions in the permeability during the shock using divalent salt solutions. These results can be explained if one looks at the total potential curves. Such curves are shown in Figure 28 in the presence of different concentrations of calcium ions (34). This figure shows that for the entire range of salt concentrations, the clay particle pore wall interaction is in the attractive state and no particle previously adsorbed to the wall expected to escape. Therefore, once clays are exposed to Ca cations (Ca exchange state), clay sheets are held together tightly and their swelling in distilled water is only to the extent of one molecular layer

of water (67). This is because, a sufficient amount of Ca^{2+} ions remains adsorbed into the clay surface, even after long exposure to the permeating fresh water (65). Consequently, when distilled water flows through the core after $CaCl_2$ flow, no damage is observed. However, if a NaCl solution is flowed through the core after $CaCl_2$ flow, Na^+ ions replace all the exchangeable cations. In this case, the core becomes water sensitive again (see Figure 29).

Experiments carried out with mixed valency ions (Na^+ and Ca^{2+})suggested that a small amount of a soluble calcium salt in NaCl solutions may be used to prevent complete reversion of Ca exchange state clays to Na exchange state ones (15,17). This is because Ca^+ ions are selectively adsorbed onto surfaces of clays in solutions of mixed Ca and Na ions. It has been shown that formation damage is virtually eliminated when the solution composition is adjusted to give calcium surface coverages greater than a critical value of 75% (34).

3.2.1.3. Type of Monovalent Cation

Experiments similar to those shown in Figure 25 have been conducted for various monovalent salts (65). Results show that CSC varies considerably with the type of monovalent cation. The maximum value is reported to be 0.071 M for Na ions and the minimum value is reported to be 0.006 M for Cs ions. Values of CSC for other monovalent ions (Li, NH_4, K) were found to lie in this interval. These differences may be related to the adsorption characteristics of different ions (34,65). As the salt concentration in the solution decreases, the number of sites on the clay surface which are occupied by the monovalent cation decreases. However, at a given solution concentration, a

greater amount of cation will remain on the clay surface for strongly adsorbed cation since they are the most difficult to be displaced. As a result a lower solution concentration has to be reached before clay particles start to disperse from the pore walls. That is, a lower CSC is obtained. The experimental observations which showed that most of cesium ions remain adsorbed on the clay surface in distilled water whereas all of sodium ions were desorbed from the clay surface in distilled water (28). This observation has been also verified by the theoretical calculations of total potential (34). Interacting potential between the clay particle and the pore wall in the presence of Cs ions is shown in Figure 29. It is seen that the particle pore wall interaction energy is in attractive state down to a concentration of about 0.009 M. This value agrees closely with the experimentally observed CSC for cesium.

3.2.2. Effect of pH

The early experiments carried out with strong acids and bases revealed that the pH of the flowing solution has an important effect on formation damage (18). In particular, it has been shown that very high pH solutions caused a considerable amount of damage. However, at these high pH values, the formation damage is caused by particles released as a result of matrix dissolution and not as a result of dispersion. Similar results were obtained when more moderate values of pH were used. That is, generally, fluids with low pH resulted in minimal release of fines whereas exposure to high pH solutions resulted in significantly greater disturbance of the formation material (68).

The surface potential on clays and detrital grains determine the onset of

clay destabilization in a formation. Therefore, it is necessary to look at the effect of pH on surface potentials. Clay particles acquire their surface charges because of their structural nature, and as such, clay surface charges are less sensitive to changes in pH. (see Figure 30). However, edges of clays are known to interact with potential determining H^+ or OH^- ions, and thus, edge potential is a function of pH (26,34). Consequently, edges of clays will have positive charge at low pH and negative charge at high pH. Detrital grains which form pore walls and consist mainly of mineral oxide (mostly quartz) acquire their surface charge by adsorption of potential-determining ions from the interstitial brine as well. Therefore, like clay edges, detrital grains will have a surface charge which varies from positive at low pH to negative at high pH (5,49,69). This is shown in Figure 31. Higher ionic strengths compress the double layer and cause smaller value of zeta potential as shown in Figure 31. This observation agrees with previous results that the effect of pH on particle release is small at high ionic strength and that the system is more pH sensitive at low ionic strengths (49).

In the light of the information above, it is seen that clay surfaces will be attracted to oppositely charged pore walls at low values of pH. Furthermore, the attraction between positively charged edges and surfaces will also contribute to the stability of the system. Consequently, when the fluid flowing through the pores has a low pH value, no particles will be released and the original permeability will be maintained. However, if the fluid has a high pH, this will cause detrital grains and edges of clays to have the same charge as clay surfaces. In this case, clays will be released from pore walls and subsequently be entrained and lodged at pore throats causing a decline in

the original permeability.

The effect of pH as described in the previous paragraph has been observed in experiments carried out in a sandstone sample and results are shown in Figure 32 (70). Each curve in this figure represents a water sensitivity experiment with the same inlet pH during the salt and the water flow. These results show that solution pH has a marked effect on permeability as has been observed by earlier studies. A dramatic reduction in the permeability occurs when the water enters with a pH of 3.6 or higher. The degree of reduction in permeability decreases as the pH is decreased below a value of 3.6. Finally, below an inlet pH of 2.6, no fines are released and plugging does not occur. However, these results seem to be inconsistent with previous statements that below a CSC, fines migration should take place and permeability should be damaged. Nevertheless, this inconsistency is resolved when the effects of ion exchange during the water flow are taken into account. That is, the release of fines is prevented by the simultaneous effects of a low pH and the multivalent ion exchange process (70).

The pH of the injected fluid may vary due to solubilization and dissolution of formation minerals such as calcite and siderite as well due to ion exchange between injected cations and exchangeable cations on clay surfaces (70,71). Therefore, in establishing the relationship between the degree of permeability decline and pH, one has to consider that the actual pH of the solution in contact with the formation is different from the inlet pH. The variation of the effluent concentration of the dissolved calcium ions and the effluent pH during the flow of salt and water for an inlet pH of 2.4 is shown in Figure 33. The effluent pH during both salt and water flow is much greater than the pH of incoming solutions due to the dissolution of calcite

from the core. It is seen that pH decreases gradually as a result of calcite being consumed during the course of the run.

As the inlet pH is decreased, the concentration of calcium ions dissolved into the solution from the matrix is increased. The dissolved calcium ions compete with other ions, mostly hydrogen, to replace sodium ions from the clay surfaces once the fresh water flow is introduced. As a result of this exchange, the extent of permeability reduction at a given pH is less than the reduction that would have occurred if matrix dissolution were absent.

For the same run as in Figure 33, concentration of sodium ions are also shown in Figure 34 together with concentration of calcium ions. It is seen that when the flow is switched from salt water to fresh water, substantial exchange of sodium for the calcium ions on the interacting surfaces has taken place. The extent of permeability reduction of sandstone decreases as surface coverage of clay particles by calcium increases and the zeta potential decreases (34). Consequently, the system remains in the attractive state even though the solution sodium concentration falls below CSC down to virtually zero. As a result no fines are released and the core remains undamaged.

3.2.3. Temperature

The temperature has a marked effect on permeability damage. It has been shown that formation damage decreases with increasing temperature during the flow of brine in the presence of oil (51). However, when only distilled water is used, extreme permeability reduction is observed at high temperatures due to stress-induced silica dissolution at grain contacts (72).

The effect of temperature on the CSC was investigated experimentally and a direct dependence was observed (65). The CSC was found to decrease with

decreasing temperature. This result can be qualitatively explained by a DLVO type analysis (see section 2.3.3.). That is, double layer repulsion increases at higher temperatures (see Equation (7)), and consequently, the CSC is reached earlier, which means higher values of CSC are obtained.

One study investigated the effect on temperature on mechanical fines migration in actual reservoir cores (35). It was found that at lower temperatures, rate damage was somewhat less. However, one must be careful when interpreting the effect of temperature. At high temperatures, some damage may also be created by colloidal iron plugging which is a product of ferric fouling from the corrosion oxidation of the steel tubing (73).

3.2.4. Rate of Change

The swelling and dispersion of clays may also result from causes other than the absolute change in a parameter. That is, the rate of change of various parameters with time is also important in fines migration. Rapid changes in flow rate, salinity or temperature may cause plugging, whereas negligible plugging may result if the rates of change are decreased (7).

It was realized early that reduction in permeability caused by fines migration could be avoided if the salinity is decreased gradually and continuously (15,17). First, it was thought that this was due to effects similar to osmosis (17). However, the osmotic pressure was shown experimentally not to be the cause of particle release (1,19). Some researchers explained the rate dependence by the rate of expansion of double layer (1), while others proposed that it was the degree of hydration of sodium ions which caused permeability reduction when salinity was reduced too quickly (19). Therefore, it was concluded that no particles would be released if the

salinity was changed slowly enough.

The dependence of the permeability reduction on the rate of change of salinity is surprising because all the processes involved are equilibrium processes. For example, the amount of clays released when the salinity is reduced should be the same irrespective of the rate at which this change was made. Consequently, explanations based solely on double layer theory are inadequate. The assumption that clay particles are not released as the salinity is decreased slowly is unsubstantiated. Nevertheless, the rate dependence of permeability reduction implies that the process of release and capture of fines are dependent on the rate of salinity decline (46).

The analysis of effluents in experiments conducted with sandstone cores revealed that approximately the same amount of clay particles are released irrespective of the flow rate and the rate of salinity change (45). In other words, for a given drop in salt concentration below the CSC, the same number of clay particles are released. However, the amount of plugging depends on the concentration of clay particles in the porous medium (2) which, in turn, depends on the rate at which the salt concentration is decreased.

In case of an abrupt decrease in salt concentration a large number of clay particles are released in a short time and consequently the particle concentration in the flowing fluid increases rapidly. As the particle concentration increases, more particles are trapped due to bridging or "brush-heaps" at the pore throat and thus permeability is reduced. Conversely, clay particles are released over a longer period of time as the salt concentration decreased slowly. In this case, particle concentration remains lower and many clay particles do not arrive at the pore throat at the same time to cause a brush-heap effect. As a consequence, the number of clay particles trapped is

lower and the reduction in permeability is also lower. Therefore, a critical rate of salinity decline (CRSD) exists above which drastic permeability reduction occurs (25,33,46,47). This principle has also been used in designing secondary recovery operations in the field (74). The CRSD was shown to be a function of flow rate, with the CRSD decreasing as the flow rate decreases (46).

The paragraph above explains the relationship between the particle concentration and the CRSD. However, the clay particles may not be released at all under certain circumstances when the salinity decreases gradually. Permeability damage depends on the competition between the two processes of particle release and ion exchange (34). Formation damage would occur only if the dispersion process occurs before the completion of the ion exchange between dissolved calcium ions and exchangeable monovalent cations. When the salinity is decreased gradually, the lowering of the ionic strengths favors predominant coverage of clay surfaces with Ca ions through ion exchange. Hence, a further decrease in salinity will not disperse any fines despite the low ionic strength, if most of the clay surfaces are covered by Ca ions.

In addition to rapid changes in salinity, rapid changes in temperature were found to affect formation damage also (18). If a sandstone core is exposed to high temperature while drying, subsequent brine flow results in permeability reduction and the effluent contains dispersed clays. However, if the same core is dried by gradually increasing the temperature, the core shows no permeability reduction to brine flow. This was explained by dispersion of clays because of mechanical forces created by sudden vaporization of water during rapid temperature increase.

3.2.5. Extraction Process

One of the factors which contribute to binding of clay particles together is the mutual sorption of positively charged organic ions between adjacent unit layers (9,32). An example is the adsorption of high molecular weight natural surfactants on sand grains observed in an oil-wet reservoir. The desorption or chemical removal of this binding matter makes the formation more susceptible to fines migration. It was realized early that core condition, that is, whether the core is preserved or extracted, can have important effects on laboratory waterflood results (76). In particular, it was found that nonextracted cores are not sensitive to the sequence of brine and water flow (see Figure 35), but extracted cores show considerable damage (see Figure 36). Furthermore, at the same test temperature extracted cores show greater permeability reduction with NaOH than do nonextracted cores (18). The differences were attributed to the removal of the protective organic coating of heavy hydrocarbons from the grain surfaces by the extraction process (7,18).

The extraction process itself removes the adsorbed heavy ends to a varying degree depending on the fluids used. For example, extraction with toluene or heptane does not remove all the organic coating on clay surfaces and therefore these cores do not exhibit permeability damage. On the other hand, if a mixture of chloroform-acetone or hot chloroform-xylene is used, cores show a significant water sensitivity (1,18). In addition, the solvent itself may cause damage by releasing clays during extraction. It has been shown that there is a linear relationship between the observed clay swelling and the bulk dielectric constant (75). This is caused by the increase in Born repulsion as the bulk dielectric constant increases. A detailed study has

demonstrated that clay mineral properties are irreversibly altered by adsorption of petroleum heavy ends (77,78). These heavy ends consist primarily of the high molecular weight fraction of crude oil known as asphaltenes and resins. Adsorption of asphaltenes on sand is reduced but not completely blocked as the water saturation is increased. The wettability of the porous medium is also altered by this heavy end adsorption. For instance, an untreated Berea sandstone core is normally water-wet. However, treatment of the core with a solution of petroleum heavy ends renders it neutral in wettability.

A Berea sandstone core is normally very sensitive to fresh water as shown in Figure 37 (curve A). When this core is pretreated with petroleum heavy ends, however, the water sensitivity is eliminated as shown in curve B. In this case, the particles are stabilized by adsorbed asphaltenes and resins. When the adsorbed material is removed by extracting the core with boiling chloroform-acetone mixture, some of the water sensitivity is restored (curve C).

There is a possibility that the mechanism of adsorption may have already taken place in the reservoir. Thus, the clay minerals in the reservoir would not be sensitive to fresh water as they would normally be. In such a reservoir, although clay minerals may be identified as those which would cause potential damage, they may in fact be in a state which would not cause formation damage.

Therefore, care must be taken to ensure that core cleaning procedures do not alter the native state of the rock and thereby change interpretation of the data.

3.3. FORMATION DAMAGE DUE TO GEOCHEMICAL TRANSFORMATIONS

Geochemical transformations such as dissolution, precipitation, and chemical reaction can take place when fluids are injected into a reservoir (35,37). That is, formation damage through geochemical processes can be very significant during some enhanced oil recovery or stimulation operations. For example, when carbon dioxide is injected into carbonate formations, the carbonate cement may be dissolved releasing mobile fines. An additional damage may result if the dissolved carbonates precipitate near production wells as carbon dioxide leaves the solution due to decreased pressure (79, 80).

Another example of this type of formation damage occurs during thermal recovery processes. The steam generator condensate is usually low in ionic strength and high in alkalinity (41,81). At high temperatures, such alkaline water dissolves silica and may cause mineral reactions. As this fluid reaches cooler parts of the reservoir, the dissolved silica can precipitate and cause plugging as well as cementation. When steam condensate contacts the formation, mineral transformation reactions cause dolomite and kaolinite to dissolve, together with analcime, calcite, smectite, and chlorite formation (82,83). Smectite, chlorite and analcime growing as pore linings and at the pore throats could result in significant permeability reduction.

Permeability damage may also result during formation stimulation operations (37). For example, HCl may dissolve chlorite and form amorphous silica gel that fills open spaces in the formation. Hydrofluoric acid attacks silicate minerals and results in silica precipitation; or if it contacts carbonate formations, it attacks carbonate minerals and precipitates calcium fluorite.

CHAPTER 4

4. CONCLUDING REMARKS

A state-of-the-art review of fines migration in oil reservoirs was presented in the preceding sections. It is evident that formation damage which results from fines migration is a complex phenomenon affected by many factors. It seems that the degree to which a particular formation can be in damaged is very difficult to predict a priori. Therefore, carefully designed laboratory experiments should be conducted in preserved cores under reservoir conditions in order to investigate the effects of process parameters.

There is still a need to carry out detailed investigations as to the effect of various factors. This is because either there is limited information or the information, which exists is contradictory in certain areas. Research will be carried out at PRI to provide information on various factors which affect fines migration in unconsolidated heavy oil reservoirs, including the effect of multiphase flow and the effect of net confining pressure.

CHAPTER 5

5. EXPERIMENTAL STUDIES

A schematic diagram of the experimental set-up is shown in Figure 38. A twin cylinder Ruska pump is used to obtain the desired constant flow rate. The flow multiplier is a floating piston stainless steel cylinder. The pump injects hydraulic oil into the flow multiplier which is connected to a stainless steel methylene chloride cylinder on the discharge side. The displaced methylene chloride, in turn, displaces the KCl brine from a monel container into the core.

All flow lines and valves downstream of the monel vessel, end caps of the core holder, and the back pressure regulator are titanium to prevent the rusting of the lines. It is important to prevent this rust, first, because it may cause particles to be released from flow lines. These particles themselves will also act like fines and damage the core. Secondly, rust interferes with particle counts as the Coulter Counter used is based on the principle of change in conductivity.

The brine was filtered twice through a 0.2 micron millipore filter and treated with formaldehyde prior to being transferred into the monel vessel. The addition of six drops of formaldehyde per liter of brine was necessary to eliminate the growth of bacteria during experiments. The growth of bacteria may cause the permeability to be damaged prematurely.

The frozen core, which was contained in a lead sleeve, was placed in a core holder capable of applying 34,500 kPa (5000 psi) overburden pressure. The core was 3.8 cm in diameter and 14.6 cm in length. The pressure drop across the core was measured by a high precision transducer and was recorded on a chart recorder. The back pressure regulator at the outlet end was set at

1379 kPa (200 psi) for overburden pressures higher than 2068 kPa(300 psi) and at 689 kPa (100 psi) for the overburden pressure of 2068 kPa.

CHAPTER 6

6. EFFECTS OF NET CONFINING PRESSURE AND VELOCITY ON FINES MIGRATION

6.1. Introduction

Much of the previous work in the area of fines migration is directed towards consolidated formations and light oil reservoirs. These results are not directly applicable to fines migration problems encountered in unconsolidated, heavy oil reservoirs. Most heavy oil reservoirs are found in high porosity, friable sandstone formations. These materials have little or no grain-to-grain cohesion, no significant tensile strength, and behave like very dense sands when subjected to stress changes showing much dilatancy and non-linear behavior (84,85). In such formations, the distinction between fines and the matrix is not very clear and the same particle may be considered part a of the matrix or the fines depending on its location and stresses imposed on it by surrounding particles. Moreover, unconsolidated sands expand greatly as the pore pressure is increased and this can release additional fine particles.

One of the widely used enhanced oil recovery techniques in Alberta's heavy oil reservoirs is the steam injection. Generally, such a technique employs a cyclic steam injection procedure to establish the initial communication and in activity followed by a steam drive. This process sometimes encounters problems.

One problem which had been brought to our attention by an operating company was related to the cyclic steam injection practice in the Lindbergh field: steam was injected as planned without any difficulties. Injection pressures were below the fracturing pressure. Therefore, it was believed that

the formation was not fractured during injection. When the wells were put on production, production rates were less than that during primary production before the first injection cycle had started. This was contrary to the expectation that the steam stimulation would have increased production rates above the present values.

If one takes into account the geochemical transformations and chemically induced fines migration, it can be concluded that formation damage should have occurred during injection as well as during production; and, injection rates should have been lower than those which were achieved. However, as the injection cycle encountered no problems this possibility was eliminated. Therefore, the only other alternative mechanism of formation damage seem to be the mechanical one. The factors which affect mechanical fines migration were considered. It was concluded that any type of mechanical damage which occurs during production should have also occurred during injection. Consequently, existing fines migration literature does not provide an answer to this phenomenon encountered during steam stimulation.

Another factor which can affect the mechanical fines migration damage is the overburden pressure or the net confining pressure (NCP). Furthermore, the net confining pressure, defined as the overburden pressure minus the pore pressure, is different during injection from that during production. That is, there is a possibility that one of the parameters which can affect the formation damage to a varying degree during injection and production cycles is the NCP. Therefore we set out to investigate how the NCP affects the mechanical type of formation damage.

It has been shown that the permeability, pore volume, and porosity of a given formation decreases with increasing the net confining pressure (86-89).

A large portion of the reduction occurs rapidly at low net confining pressures. At higher pressures, these properties still continue to decline by progressively smaller amounts.

Therefore, it is apparent that the overburden pressure (or net confining pressure) is one of the factors which should have an impact on the extent of formation damage in oil-bearing formations. This is true for both consolidated and unconsolidated formations. As can be expected, the effect of NCP will be more pronounced in unconsolidated formations. However, the effect of NCP on formation damage has never been studied before. Consequently, the aim of this report is to investigate the effect of net confining pressure on fines migration in unconsolidated, heavy oil reservoirs.

6.2. EXPERIMENTAL RESULTS

A preserved core sample was obtained from the Lindbergh reservoir located in the Cold Lake area in Alberta. The Lindbergh field produces from the Lower Grand Rapids formation which is from 500 to 625 m deep. The net pay thickness is between 13 to 20 m, porosity is 33% and the oil viscosity is 100,000 mPa.s at the reservoir temperature of 24 $^{\circ}$C. The permeability is generally between 2 to 3 μm^2. However, the sample used in this study came from a particularly poor part of the formation (Cummings "C" sand) and had an undamaged permeability of 0.064 μm^2. Therefore, this core would be representative of the worst part of the Lindbergh reservoir.

The sample was analyzed using scanning electron microscopy (SEM), X-ray diffraction (XRD), and other pictographic tests. The results of sieve analysis are shown in Figure 39. The majority of grains lie between 125 to 250 microns size fraction. The sand grains are sub-angular and poorly

cemented by clay (Figure 40). The results of XRD analyses carried out on the bulk and fines fraction (< 2 μm) indicate that a large portion of fines consist of kaolinite (Table 2); no swelling clays have been found in the fines fraction.

Having studied the sample under SEM, it has been concluded that the majority of clays lack a well defined crystal habit and are interpreted as being detrital in origin. This is shown in Figure 41. There are also small amounts of antigenic kaolinite as shown in Figure 42. Results of the XRD analysis of the produced fines in the effluent indicated that the migrated fines in the core consisted of approximately 95% kaolinite, 3% quartz, and 2% illite.

The core was cleaned with methylene chloride at low rates and dried by injecting nitrogen at room temperature. Initial air permeability was measured and the equivalent liquid permeability was found to be 0.065 μm^2 and 0.043 μm^2 in the forward and reverse directions, respectively, at an overburden pressure of 3447 kPa (500 psi). The difference between the permeabilities measured in the forward and reverse direction is probably due to the existence of very small amounts of coal in the core. The coal flakes act like check valves hindering flow in one direction while permitting flow in the other.

As the objective was to investigate the effect of NCP on the mechanical fines migration, 10,000 ppm KCl brine was used for all the experiments. The results of critical rate experiments in the forward direction at the NCP of 3447 kPa are shown in Figure 43. The undamaged permeability was approximately 0.062 μm^2 which compared favorably with the equivalent liquid permeability in this direction. The critical velocity was 0.0101 cm/s. The damaged permeability was about 0.011 μm^2 or 18% of the original permeability.

Next, the brine was injected in the reverse direction and the NCP was changed to 2068 kPa. The results are shown in Figure 44. It was seen that the permeability decreased slightly over the range of velocities used. However, at the end of each high rate run, a low rate run (at 0.0012 cm/s) was carried out and it was observed that the original permeability was retained. Therefore it was concluded that the critical velocity was higher than the maximum velocity which could be obtained by the Ruska pump used in this study (0.0236 cm/s). The observed permeability decline is probably due to the turbulence at high rates which manifests itself in higher pressure drops. This is not taken into account by the Darcy's law.

Finally, the NCP was adjusted to 10,342 kPa (1500 psi) and the brine was injected in the forward direction again. This time, the undamaged permeability was 0.039 μm^2 and the results are shown in Figure 45. The critical velocity was found to be 0.0052 cm/s which was also confirmed by carrying out experiments at the low rate of 0.0012 cm/s. The damaged permeability at the highest attainable rate was 0.024 μm^2 or 62% of the original permeability. However, it is possible that further damage would have resulted if the flow rate could have been increased to higher values.

The changes in the critical velocity at different NCP's for a given core are a result of changes in the pore structure with the NCP. In order to find out the nature of these changes, the following series of experiments were carried out on preserved cores from the Marguerite Lake reservoir (Clear water formation). These cores were cut adjacent to each other from a section with no heterogeneities. The homogeneity of this particular section was also confirmed from X-ray negatives.

A given sample was cleaned with methylene chloride. After drying, the

sample was confined at a specific NCP, evacuated, and injected with Cerebrally (melting point 70 °C) at approximately 80 °C. Once the sample was fully saturated, it was isolated and cooled slowly to room temperature while keeping a constant NCP. This way, it was possible to cut thin sections from the solidified sample and to analyze it for possible changes in the pore structure.

Three samples were obtained from a relatively homogeneous section of the preserved core. A different NCP was applied to each sample following the procedure described above. These pressures were 1400, 6900, and 20,700 kPa. Petographic thin sections and polished SEM mounts were made from these samples. Thin section photographs are shown in Figure 46 and SEM photomicrographs are shown in Figure 47.

Image analyses were performed on photomicrographs taken at sixteen randomly chosen areas at each NCP. The resulting mean values of pore and pore throat sizes are shown in Table 3 together with standard deviations. However, it should be mentioned that standard deviations in this case are more related to the pore size distribution in porous media than to the actual error in the measurements. That is, a porous medium having a wider pore size distribution will exhibit a higher standard deviation. Therefore, too much emphasis should not be placed on standard deviations; rather, mean values are more significant.

6.3. EFFECT OF NET CONFINING PRESSURE

Results from all the experiments are shown in Figure 48. First, the results show that the net confining pressure is one of the important parameters in fines migration phenomenon encountered in unconsolidated, heavy oil reservoirs. Secondly, the critical velocity decreases as the net

confining pressure is increased.

The net confining pressure is the overburden pressure minus the pore pressure. It is responsible for stresses which exist in the porous medium. The changes in the porous medium that occur with the change in these stresses are shown in Figures 46, 47, and in Table 3. It can be seen from these figures that the porous medium becomes more compact, grains are packed more efficiently, and pore and pore throats become smaller as the net confining pressure is increased. This is also verified by the results of image analyses presented in Table 3. Furthermore, the undamaged or the starting permeability decreases as a result of these changes in the porous medium.

The changes observed with increasing net confining pressure agree with the observations of porosity as a function of NCP in the literature (90). These changes are interpreted for cores obtained from heavy oil reservoirs as shown in Figure 49. It can be seen that the pressure has to be increased above a certain value in order to observe significant changes in porosity. It seems that this pressure lies somewhere between 7000 and 20,000 kPa for the Marguerite Lake pool.

Therefore, the reduction of the pore and pore throat sizes and of the undamaged permeability with increasing net confining pressure results in lower critical velocities. This is because it is easier to bridge smaller pore throats than larger ones using the same size particles. Consequently, although the same number of particles may be mobilized at each velocity, they will tend to lodge at the pore throats in the lower velocity range in a sample confined at a higher pressure.

6.4. IMPLICATIONS FOR FIELD OPERATIONS

The fact that the critical velocity is a function of the NCP has

important implications during field operations. That is, as the NCP during injection is generally less than that during production, the fines are mobilized at a lower velocity during production than during injection. If the difference between the critical velocities is sufficiently large, it may not be possible to produce at expected rates from a formation, due to permeability damage, while injection at the same rate is possible. In fact, this has been the experience during some field operations in the Cold Lake area. Thus, the observations during cyclic steam stimulation can be explained in the light of the information obtained in this study.

6.5. PRECAUTIONS FOR LABORATORY TESTING

In order to prevent the mechanical formation damage during different field operations, experiments should be conducted on preserved and carefully cleaned samples. These experiments should be carried out at different net confining pressures corresponding to actual field values during various operations. Thus, field injection rates can be kept below the critical rate obtained in the laboratory for each of these operations so that minimum mechanical formation damage results.

6.6. EFFECT OF CORE PERMEABILITY

The effects of velocity and net confining pressure (NCP) on fines migration and permeability damage in tight formation are significant as were shown in previous sections. It is of interest to examine the effects of velocity and NCP and on permeability damage for cores having high permeabilities. Figures 50 to 52 show the effect of injection flow rate on permeability at NCP of 200 psi, 900 psi and 1800 psi, respectively. To avoid clay swelling and chemical fines migration, the injected fluid has 3% KCl. To determine the critical flow rate at which fines migration occurs, the flow

rate was increased in small increments. The core used in these tests was obtained from Frog-Lake McLaren sand. Figure 50 shows that the effect of increasing flow rate up to 35.4 ml/min on the core permeability at a NCP of 200 psi. One observes that the permeability is independent of the flow rate, i.e., there was no permeability damage occurred due to mechanical fines migration. There was no permeability damage at NCP of 900 psi and 1800 psi as shown in Figures 51 and 52. The results shown in Figures 50 to 52 show that unlike the trends observed with cores having small permeabilities, the effect of flow rate on the permeability of cores having high permeabilities is insignificant.

6.7. EFFECT OF FLUID (WETTING) VISCOSITY

Figure 53 shows the effect of the flow rate on the permeability for the same core at a NCP of 1800 psi. A water-gylcerine solution having a viscosity of 56 mPa.s at 23 °C was used. The flow rate was again increased in small increments up to 17.7 ml/min. There is no permeability damage occurring due to injecting the gylcerine solution. From the results shown in Figures 50 to 53, one can conclude that permeability damage due to mechanical fines migration in cores having high permeability is insignificant.

6.8. EFFECT OF IONIC STRENGTH

To examine the effect of ionic strength on permeability, de-ionized water was injected into the same core at a flow rate of 7.8 ml/min. Figure 54 shows the change of permeability as a function of the effluent volume. One observes a significant decrease in permeability due to decreasing the ionic strength. It is obvious that decreasing the ionic strength causes the clay particles to disperse in relatively large concentrations. These clay particles deposit into pore throats and damage the core. To verify this explanation, the flow

direction was reversed and the core permeability was measured. One observes in Figure 54 that there is a temporarily increase in permeability due to change flow direction. However, this does not restore the permeability.

To restore permeability damage due to chemical fines migration, the core was injected with KCl and $CaCl_2$ solutions having various concentrations. Figure 55 shows permeability changes as a result of injecting these solutions. One observes that the permeability increased upon increasing the ionic strength (salinity) of the injected fluid, especially when di-valent ions were injected. However, using high concentrations of di-valent ions can cause permeability damage due to precipitation of di-valent ions salts, e.g. carbonate and sulfate.

6.9. EFFECT OF INJECTING A NON-WETTING FLUID

Figure 56 shows permeability as a function of effluent volume for a Wolf-Lake core. The non-wetting fluid used was mineral oil of 43 mPa.s at 60°C. The flow rate was increased in small increments as was explained earlier. One observes that the permeability is independent of flow rate. This result indicates that permeability damage due to mechanical fines migration is very important when a wetting fluid is injected into a tight formation.

To remove all traces of the original oil from the core, a toluene slug was injected, then injection of the mineral oil was resumed. The permeability of the core was increased due to this treatment to approximately 60 md. Again, the flow rate was increased in small increments and the permeability was monitored. Similar to the results obtained at low permeability, the permeability was found to be independent of the flow rate.

To examine the potential permeability damage due to mechanical fines

migration, a 3% NaCl solution was injected at a flow rate of approximately 0.1 ml/min. One observes in Figure 56 that the permeability diminishes upon injecting a wetting fluid into a low permeability core.

CHAPTER 7

7. CONCLUDING REMARKS

1. A review of the literature on fines migration in porous media was conducted. As a result, various factors which affect fines migration and their relative importance in heavy oil reservoir were identified.

2. A corrosion resistant linear core displacement apparatus for fines migration experiments was built. The equipment was capable of handling unconsolidated cores (approximately 4 cm in diameter and 15 cm long) high pressures (up to 20 MPa) and high temperatures (up to 250 $^{\circ}$C).

3. A method for extraction of cores, which minimizes the permeability damage in the extraction process was developed.

4. The effects of various parameters including: net confining pressure, velocity, permeability, wettability, viscosity and ionic strength of the injected fluid on permeability damage were examined. The following trends were observed:

(i) Permeability damage due to mechanical fines migration is significant for reservoir cores having low permeabilities. The critical velocity at which permeability damage occurs was found to be a function of the net confining pressure.

(ii) Permeability damage due to mechanical fines migration is insignificant for reservoir cores having high permeabilities.

(iii) Permeability damage due to chemical fines migration is significant for all reservoir cores examined in the present study.

(vi) Inection of a non-wetting fluid does not casue any fines migration or permeability damage.

NOMENCLATURE

A_H : Hamaker's constant

C_o : Bulk electrolyte concentration

e_o : Electronic charge

h : Distance of separation

I : Ionic strength

k : Boltzmann's constant

N_A : Avogadro's constant

T : Absolute temperature

u : Defined by Equation 2

V_A : Attraction energy

V_R : Repulsion energy

γ : Tanh (u/4)

ε : Dielectric constant

κ : Inverse Debye length

ν : Magnitude of ion valence

ψ : Electrical potential

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TABLE 1

Cation Exchange Capacity

of Clay Minerals

(meq/100 g Clay)

Montmorillonite	80-150
Illite	10-40
Chlorite	10-40
Kaolinite	3-15
Sand (2 to 65)	0.2-0.3

Table 1: Cation exchange capacity of clay minerals (Reference 9)

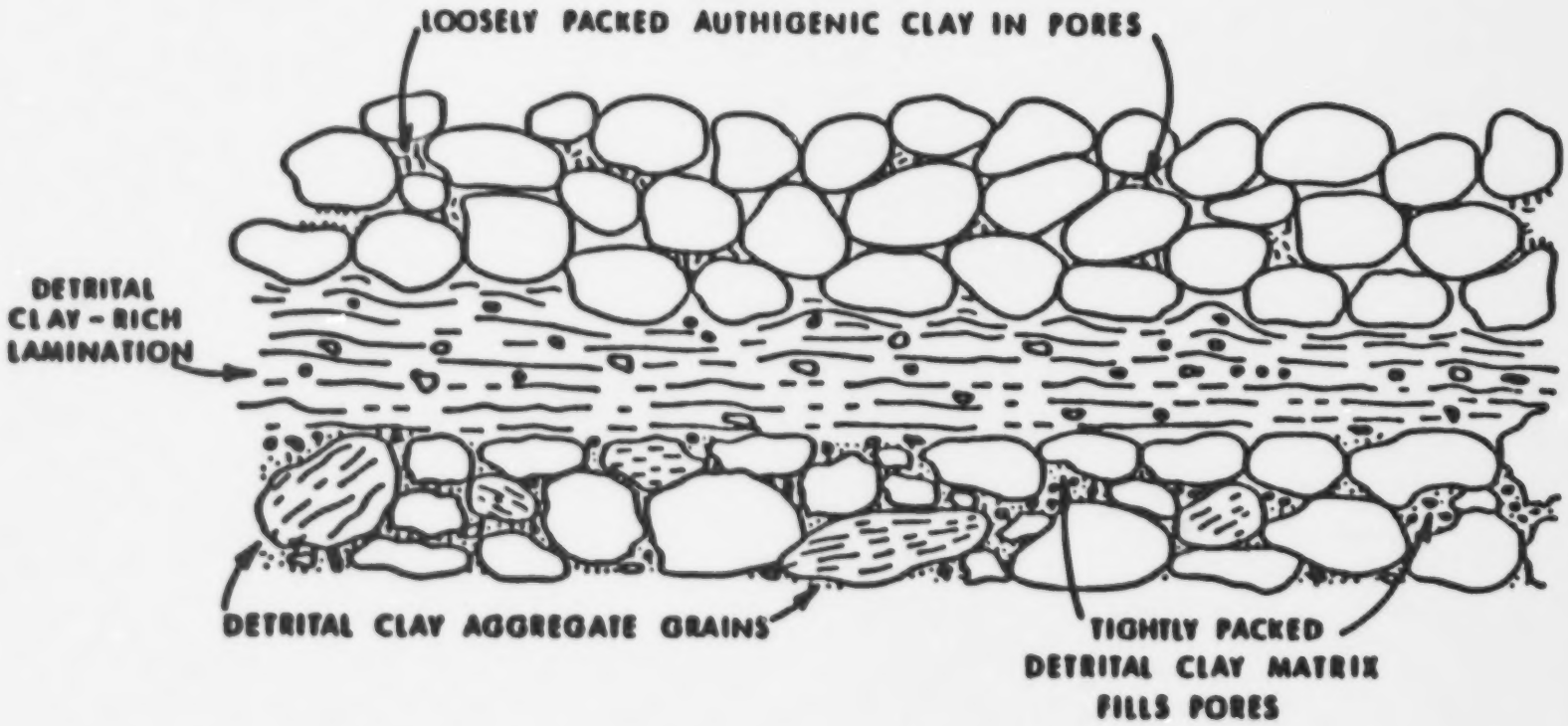

LOOSELY PACKED AUTHIGENIC CLAY IN PORES
DETRITAL CLAY-RICH LAMINATION
DETRITAL CLAY AGGREGATE GRAINS
TIGHTLY PACKED DETRITAL CLAY MATRIX FILLS PORES

Figure 1: Clay minerals in an oil reservoir
(Pittman and Thomas, 1979)

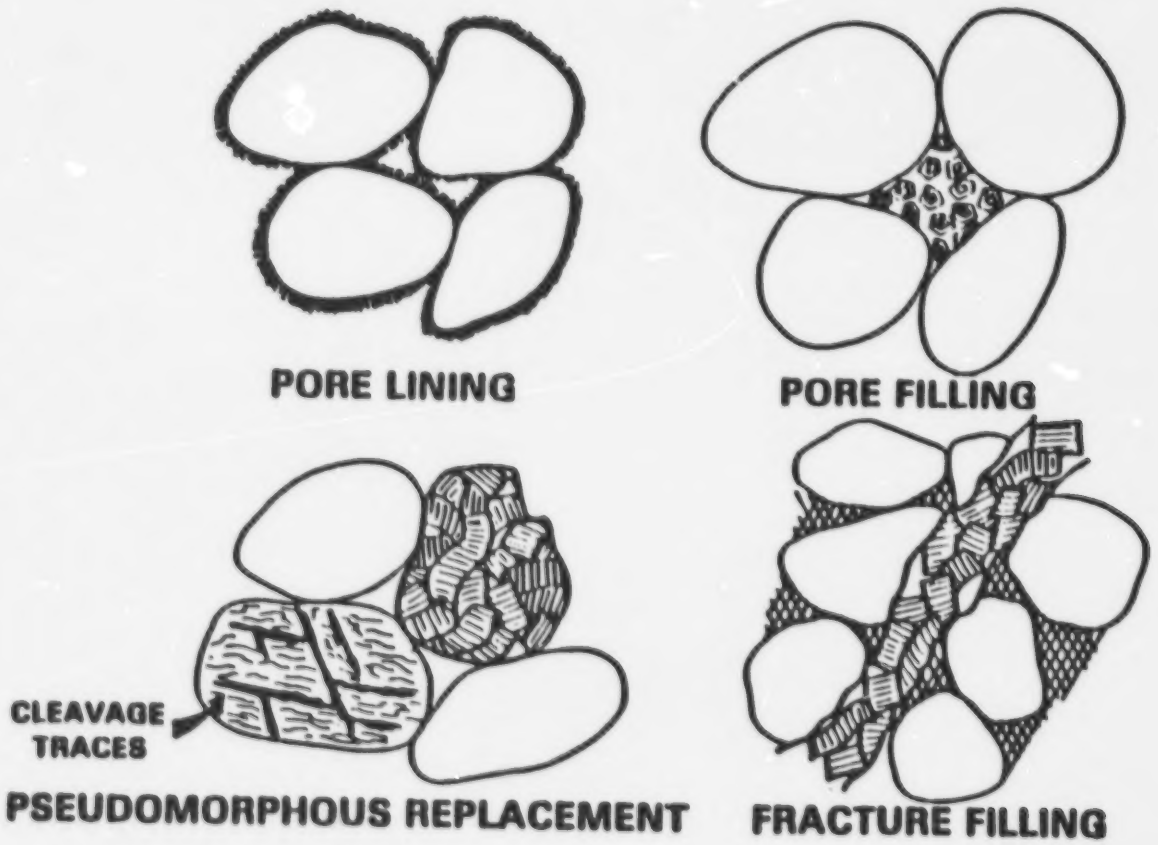


Figure 2: Modes of occurrence of authigenic clay in sandstones (Reference 12)

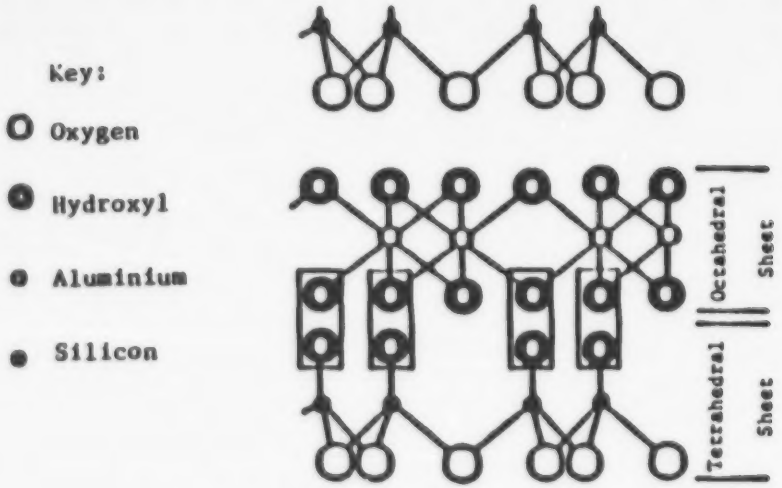


Figure 3: Schematic representation of silica tetrahedral sheet and an alumina octahedral sheet. The mode of condensation between two sheets is indicated by rectangles

(Reference 27)

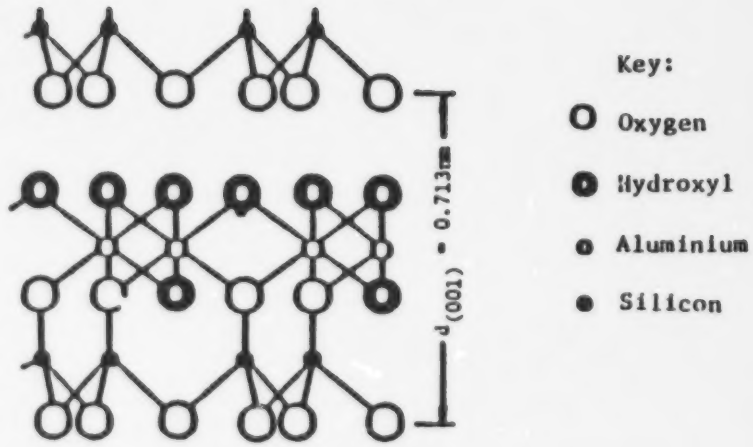


Figure 4: The layer structure of kaolinite viewed along the a-axis. The basal spacing of 0.7 nm is equal to layer thickness

(Reference 27)

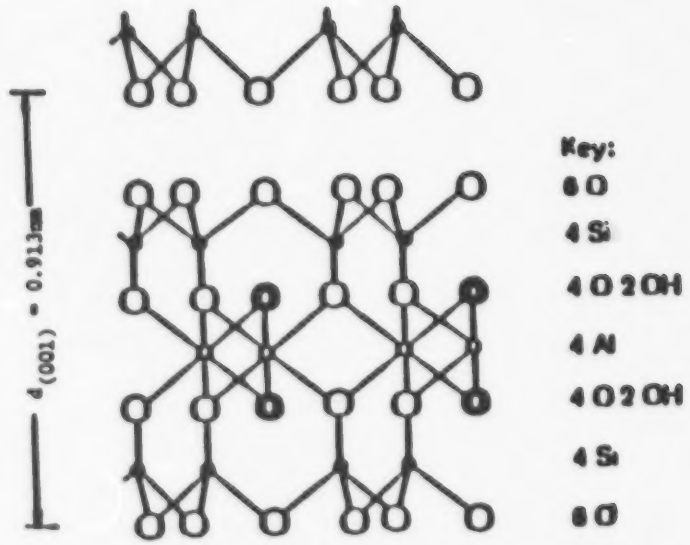


Figure 5: The pyrophyllite layer viewed along a-axis
(Reference 27)

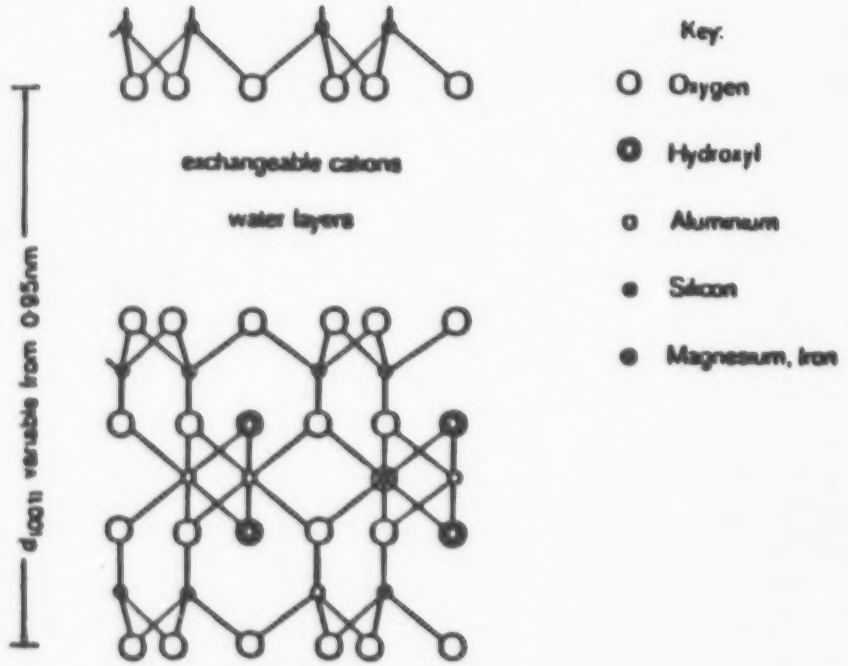


Figure 6: The layer structure of montmorillonite showing the occurrence of isomorphour replacement and the occupancy of the interlayer space by exchangeable cations and water

(Reference 27)

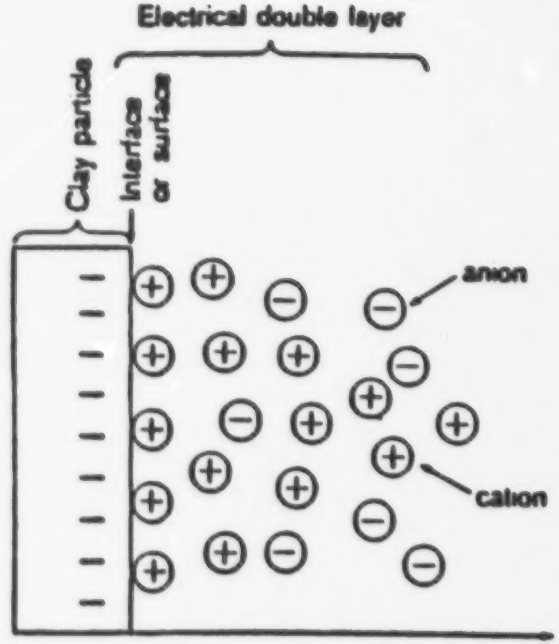


Figure 7: The structure of a diffuse electrical double layer at the surface of a clay particle or silicate layer

(Reference 27)

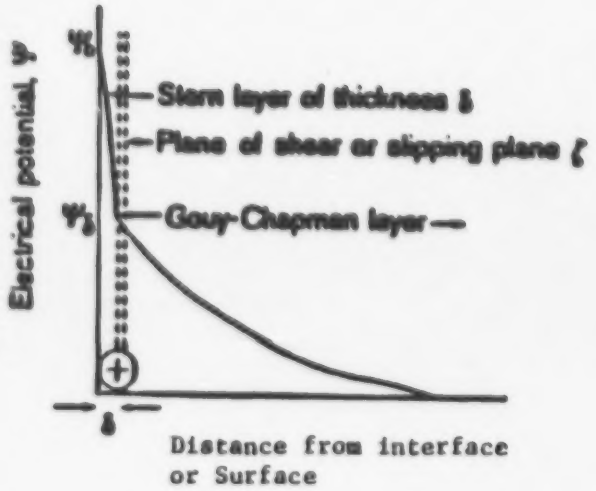


Figure 8: Variations of the electrical potential with distance from the surface
(Reference 27)

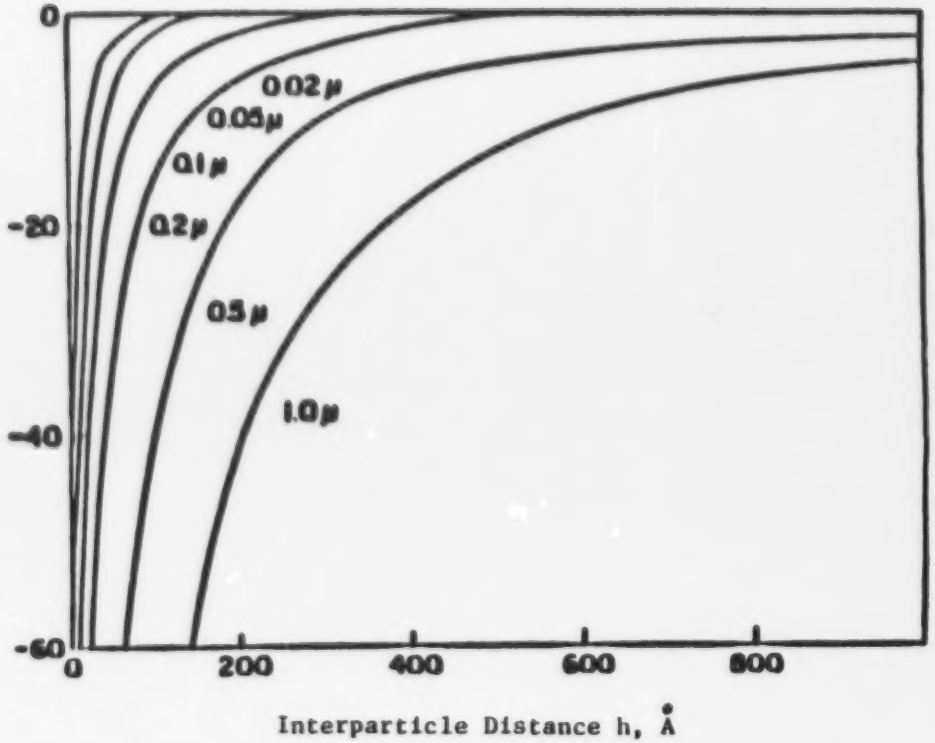


Figure 9: Attraction potential between particles
(Reference 29)

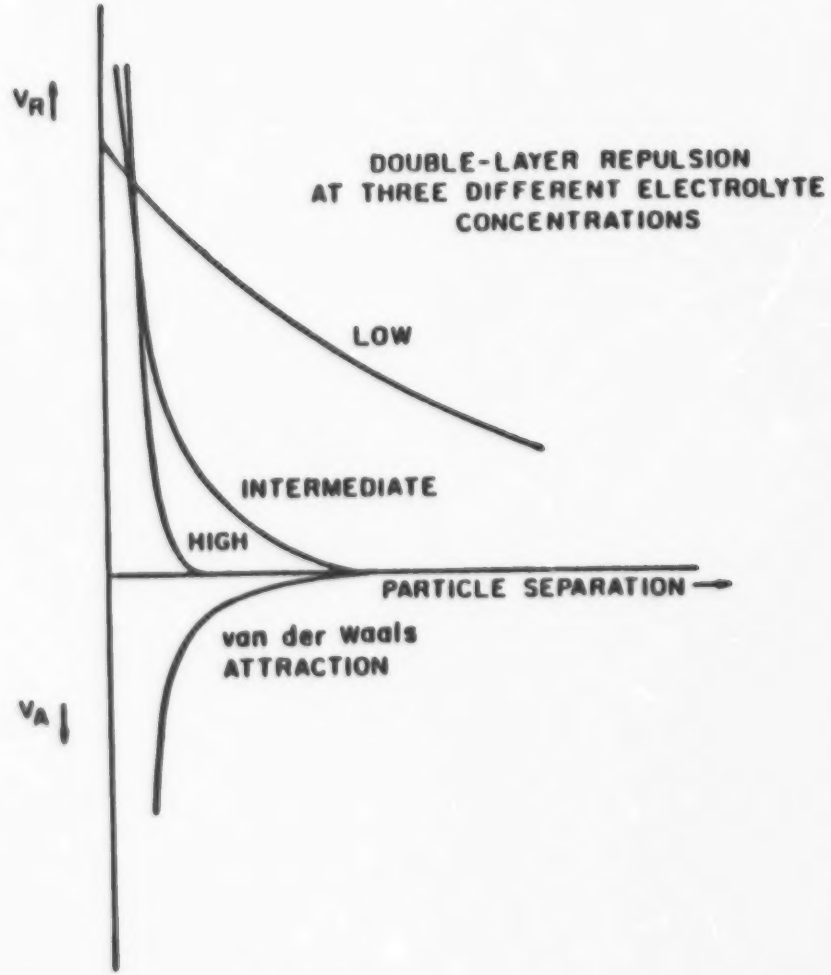


Figure 10: Repulsive and attractive energy as a function of particle separation at three electrolyte concentrations

(Reference 26)

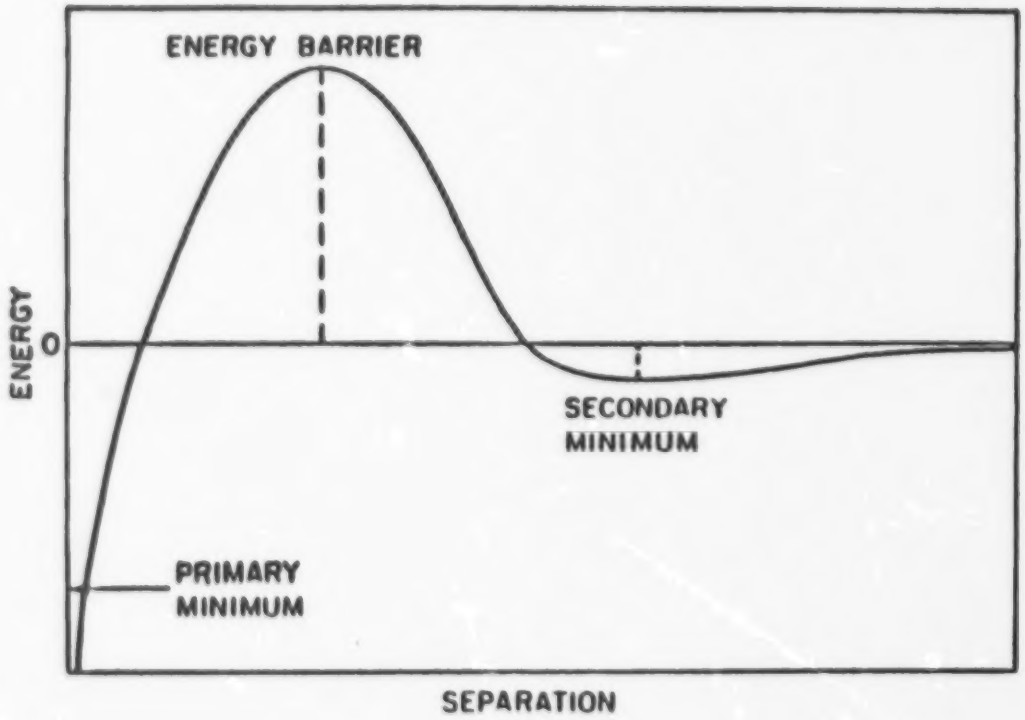


Figure 11: Interaction energy versus separation for combined van der Waals attraction and electrical double layer repulsion (Spielman, 1977)

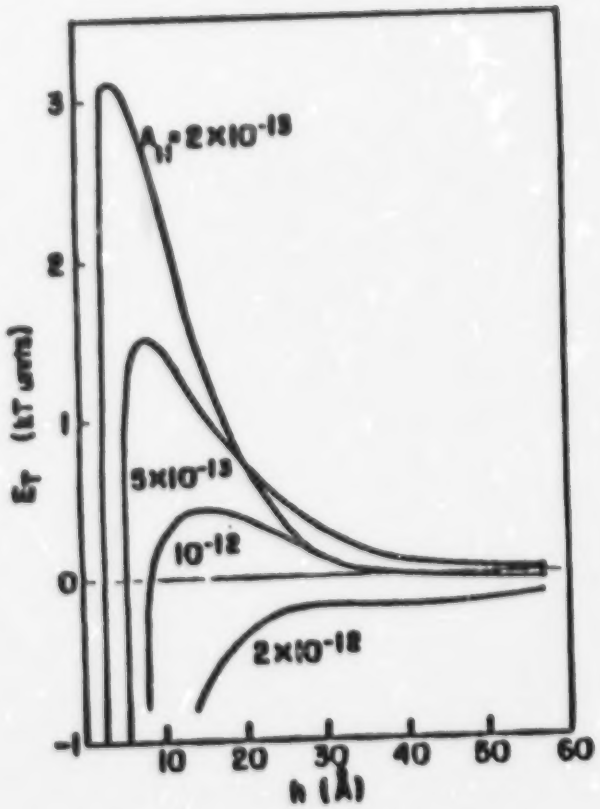


Figure 12: Total interaction energy as a function of Hamaker's constant

(Reference 29)

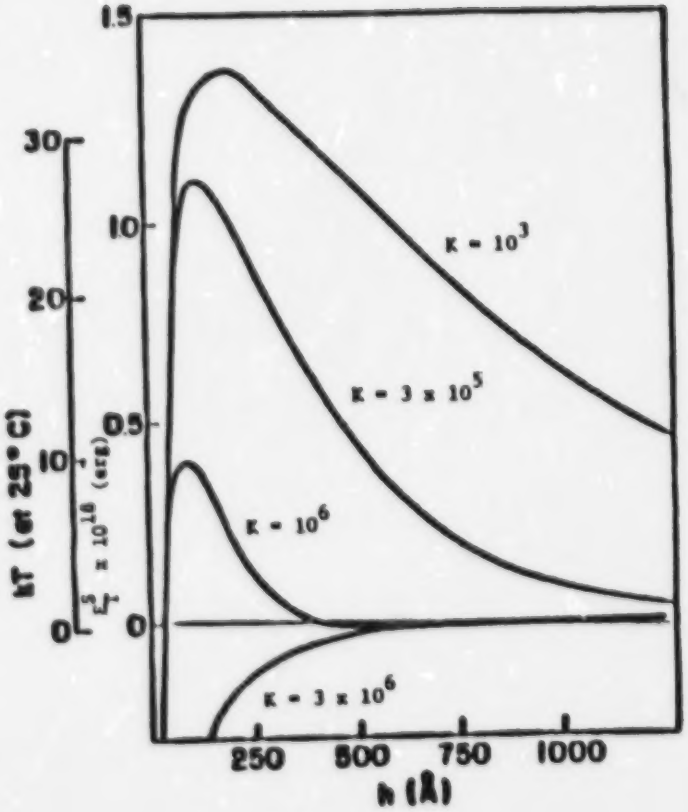


Figure 13: Total interaction energy as a function of varying electrolyts strengths

(Reference 29)

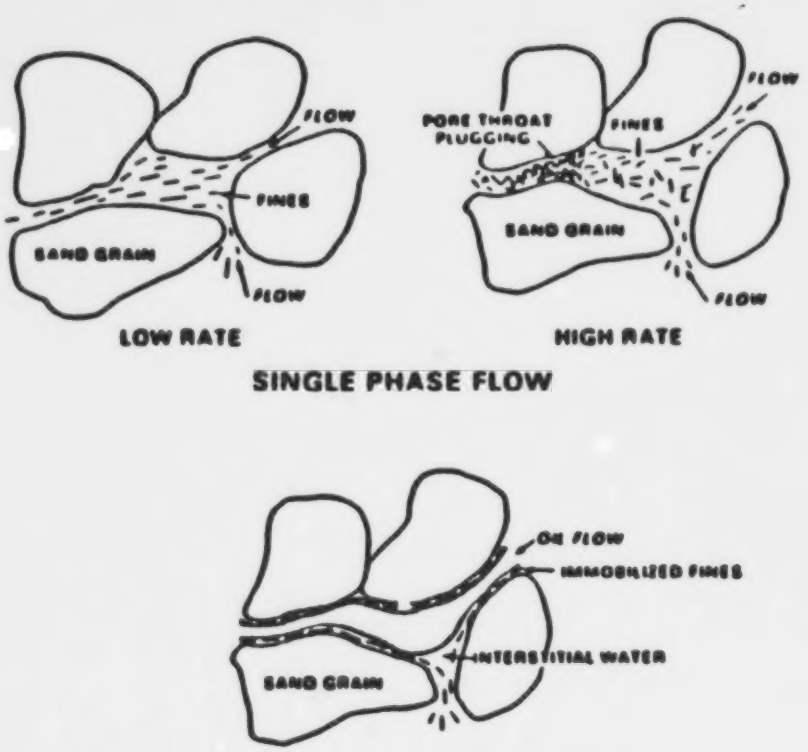


Figure 14: Flow of water-wet fines
(Reference 24)

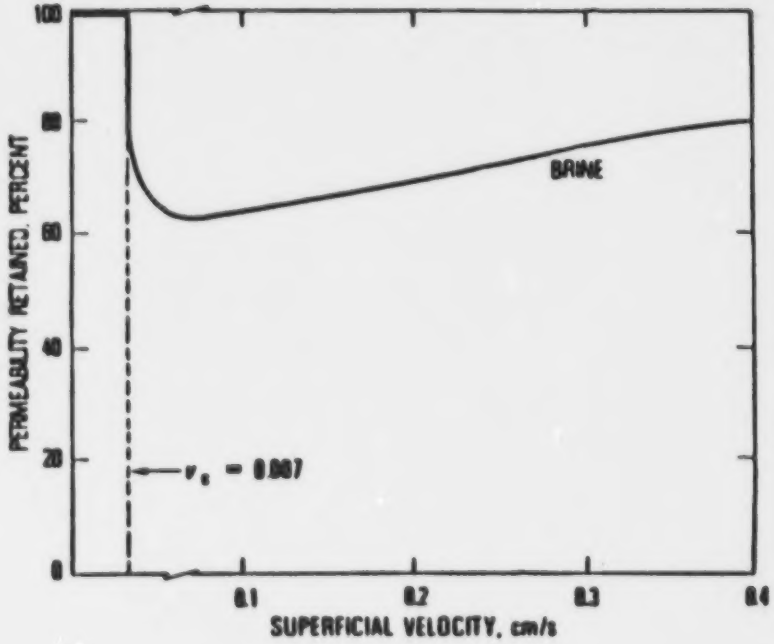


Figure 15: Brine flow above the critical velocity causes damage
(Reference 33)

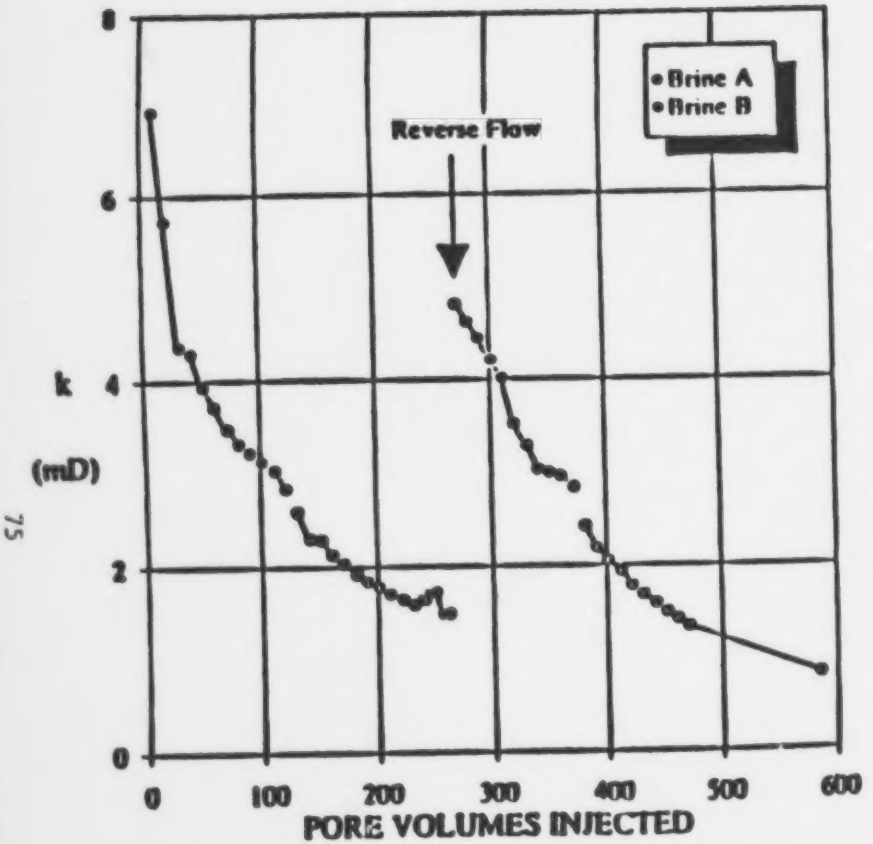


Figure 16: Permeability trend during the injection of brines A and B into a native state core

(Reference 35)

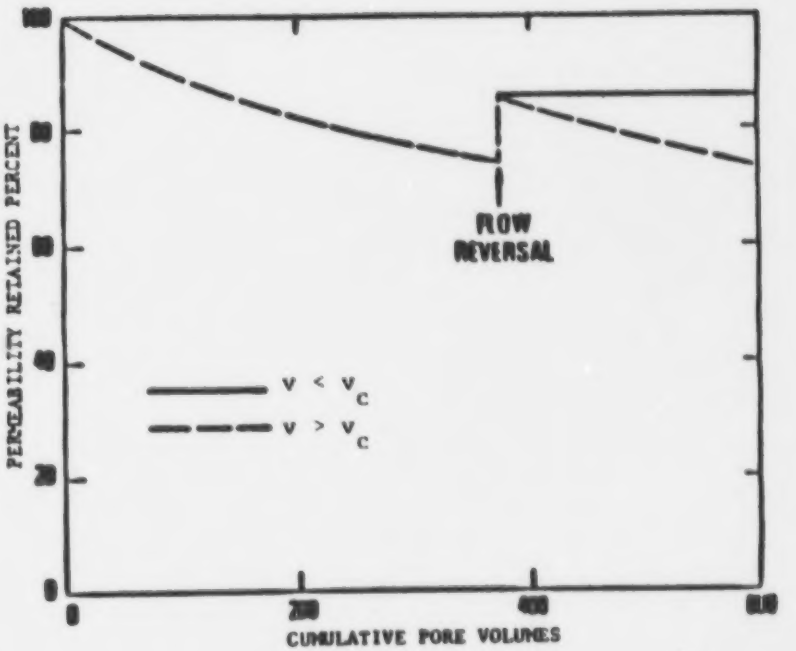


Figure 17: Flow reversal and restoration of permeability

(Reference 33)

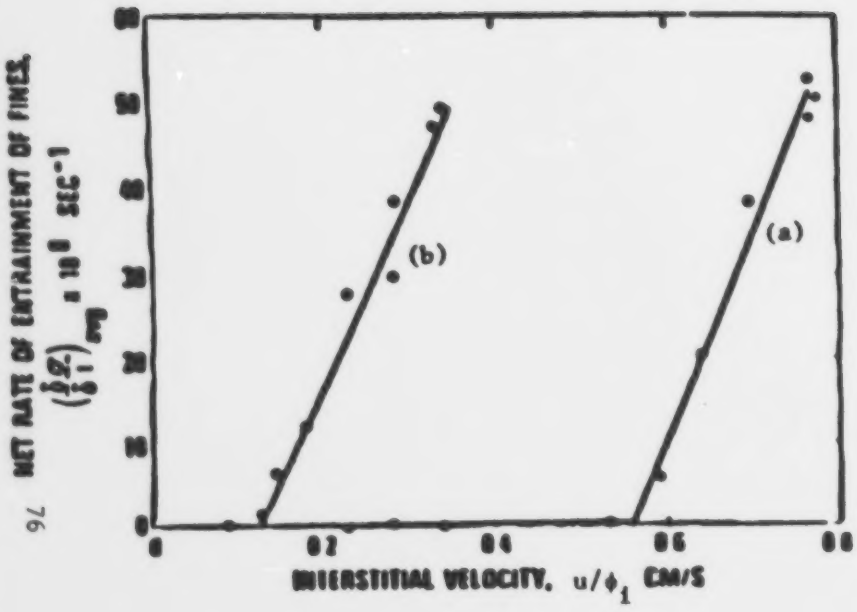


Figure 18: Net rate of fines entrainment in a porous medium, curve (a) a cp viscosity, curve (b) 10 cp viscosity

(Reference 39)

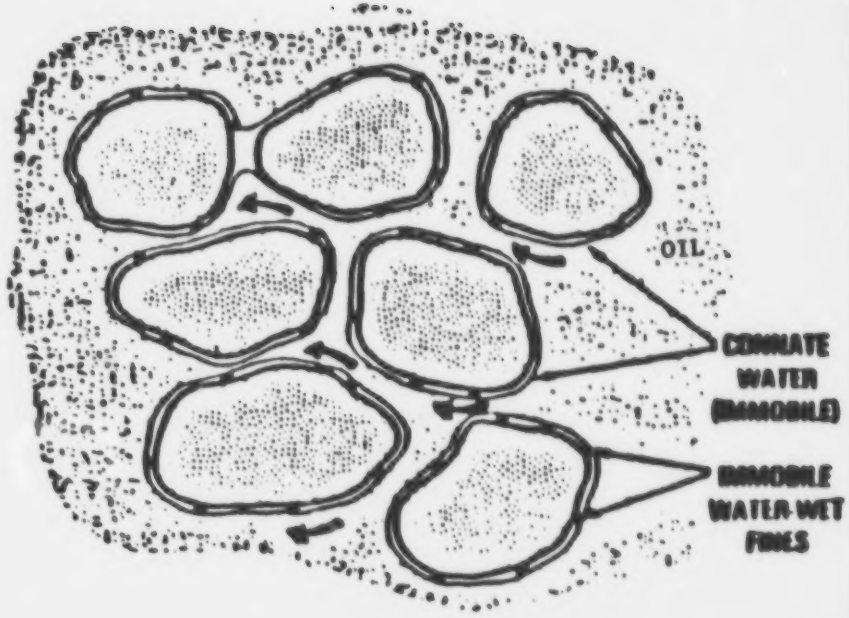


Figure 19: Water-wet fines are immobile when water phase is immobile

(Reference 2)

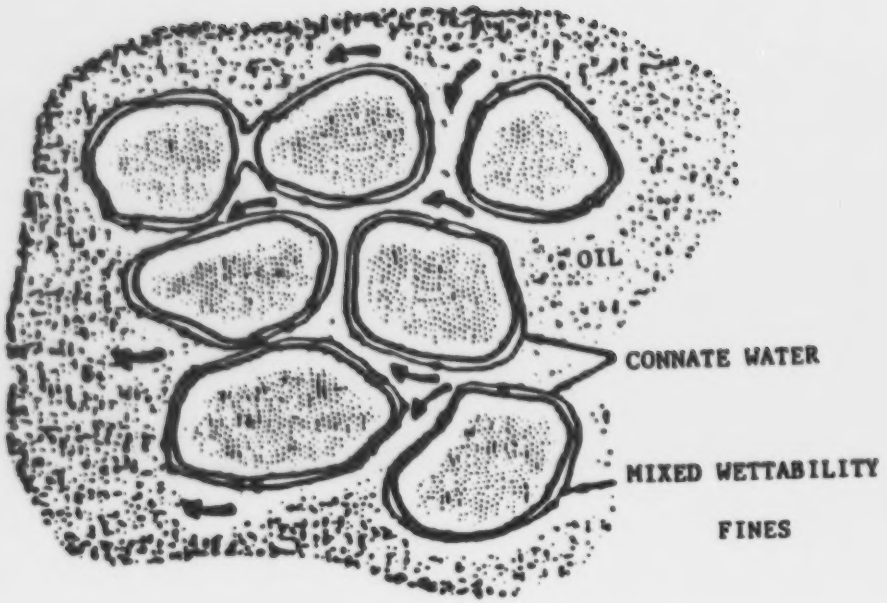


Figure 20: Fines of mixed wettability are constrained to move only along the oil/water interface

(Reference 2)

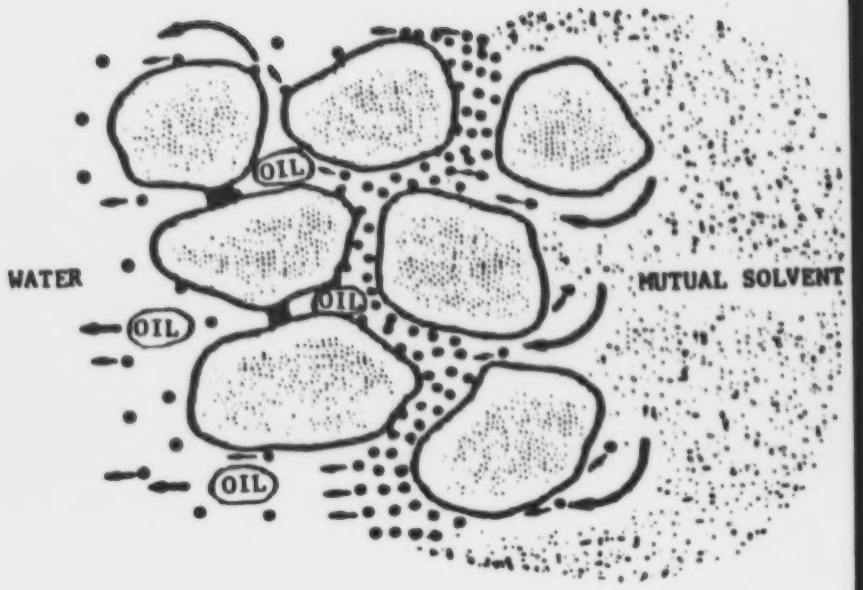


Figure 21: Mutual solvents releases fines held by wetting and interfacial forces, causing them to migrate at high concentrations

(Reference 2)

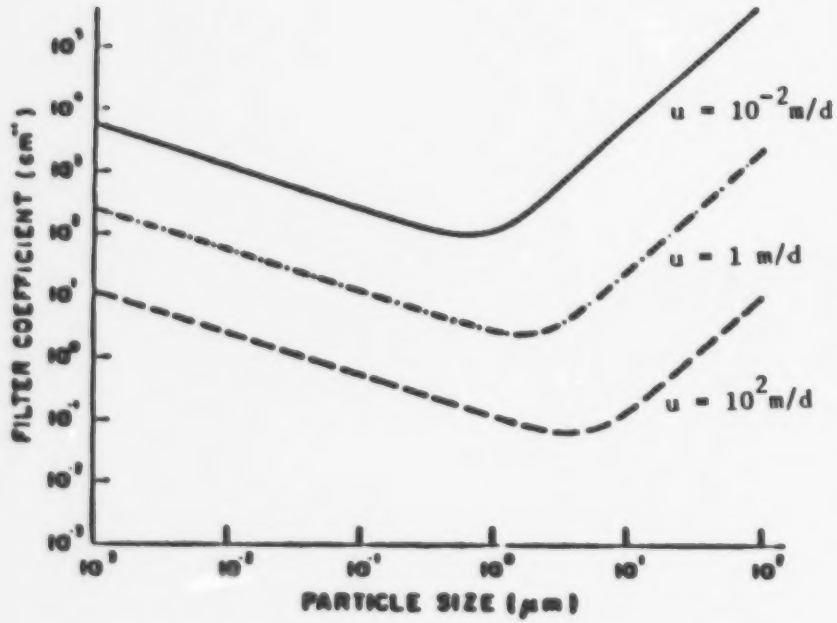


Figure 22: Filter removal efficiency for three velocities
(Reference 61)

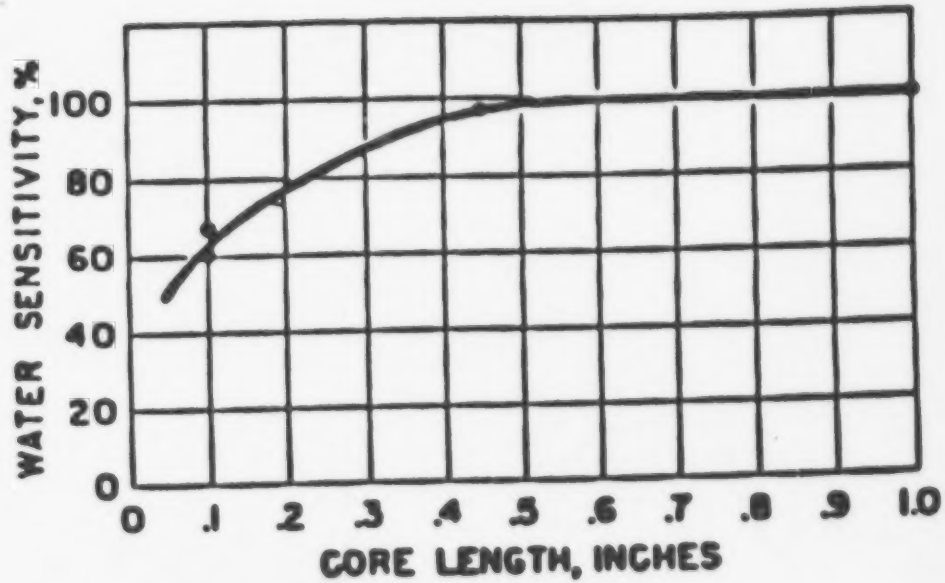


Figure 23A: Variation of water sensitivity with length for Berea Sandstone
(Reference 17)

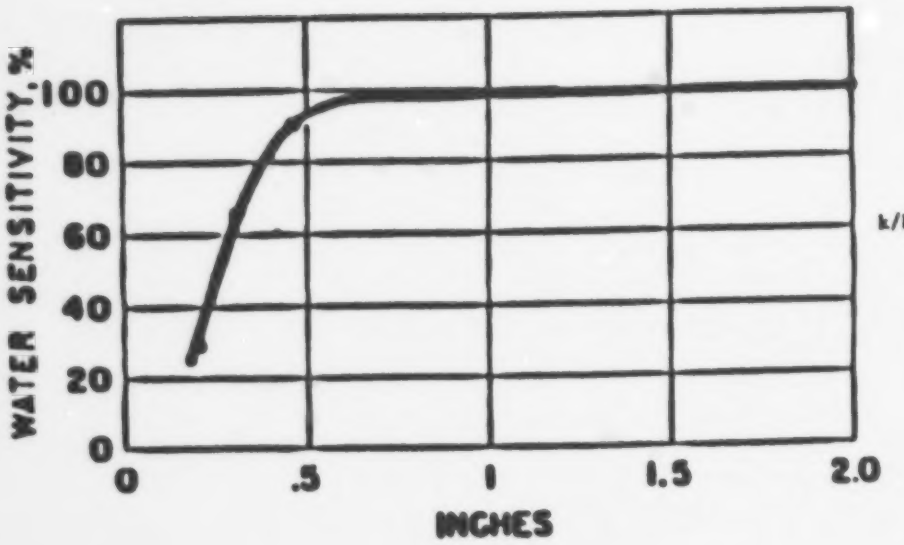


Figure 23B: Variation of water sensitivity with length for Nellie Bly Sandstone
(Reference 17)

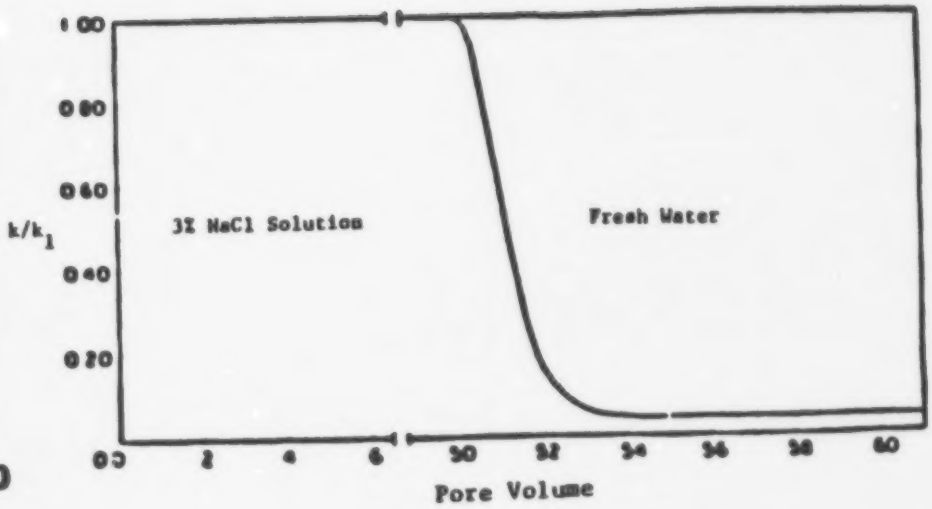


Figure 24: Permeability reduction in a typical water shock experiment
(Reference 23)

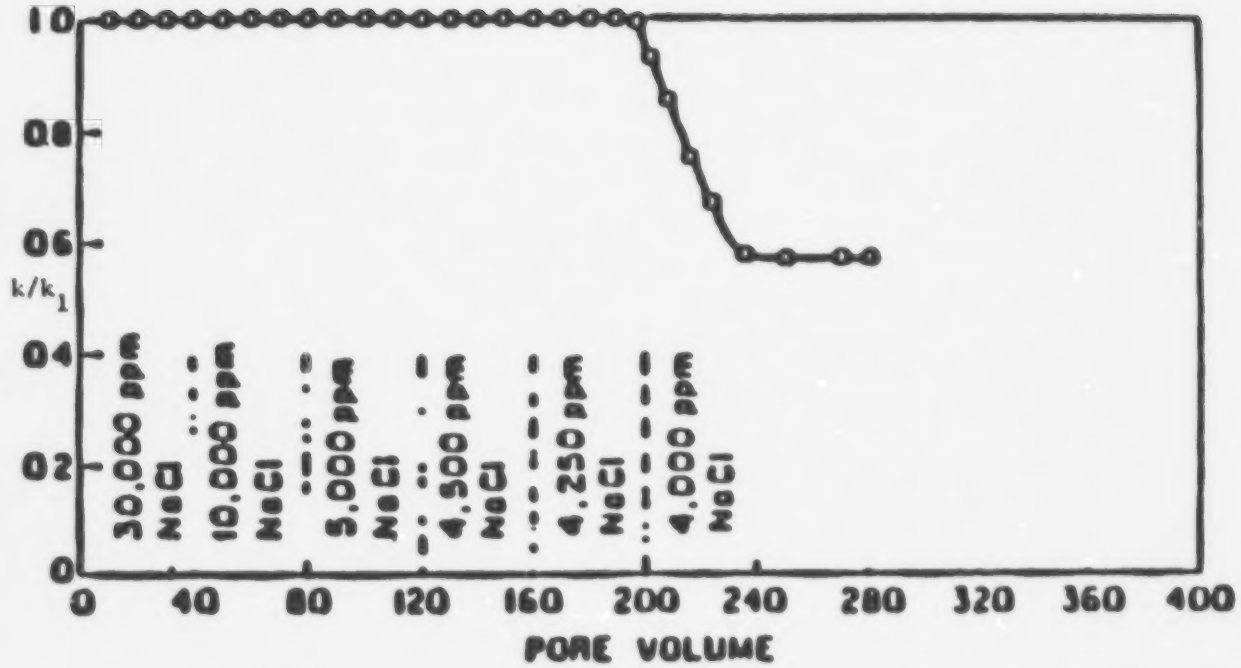


Figure 25: Critical sodium chloride concentration
(Reference 23)

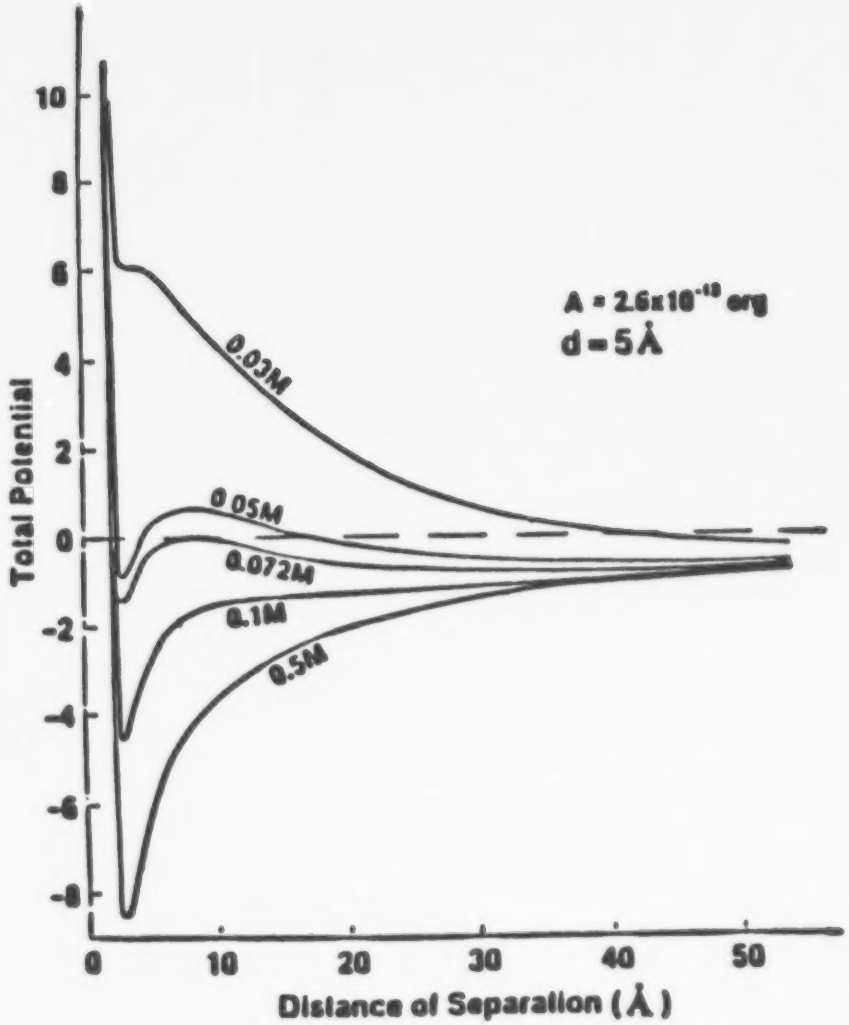


Figure 26: Total interaction potential as a function of distance of separation for sodium ions in solution

(Reference 34)

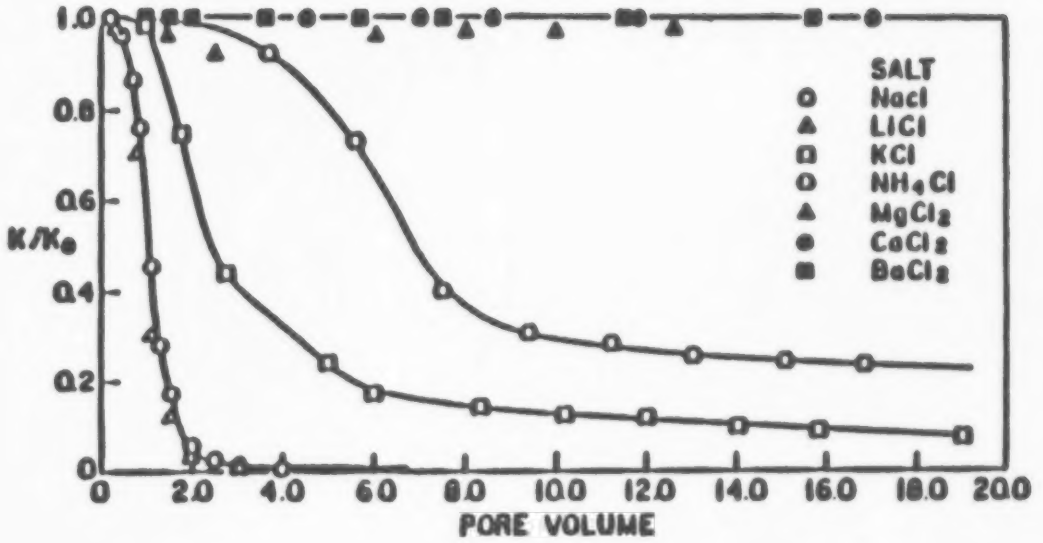


Figure 27: Effect of various cations on the fresh water sensitivity of Berea sandstone
(Reference 66)

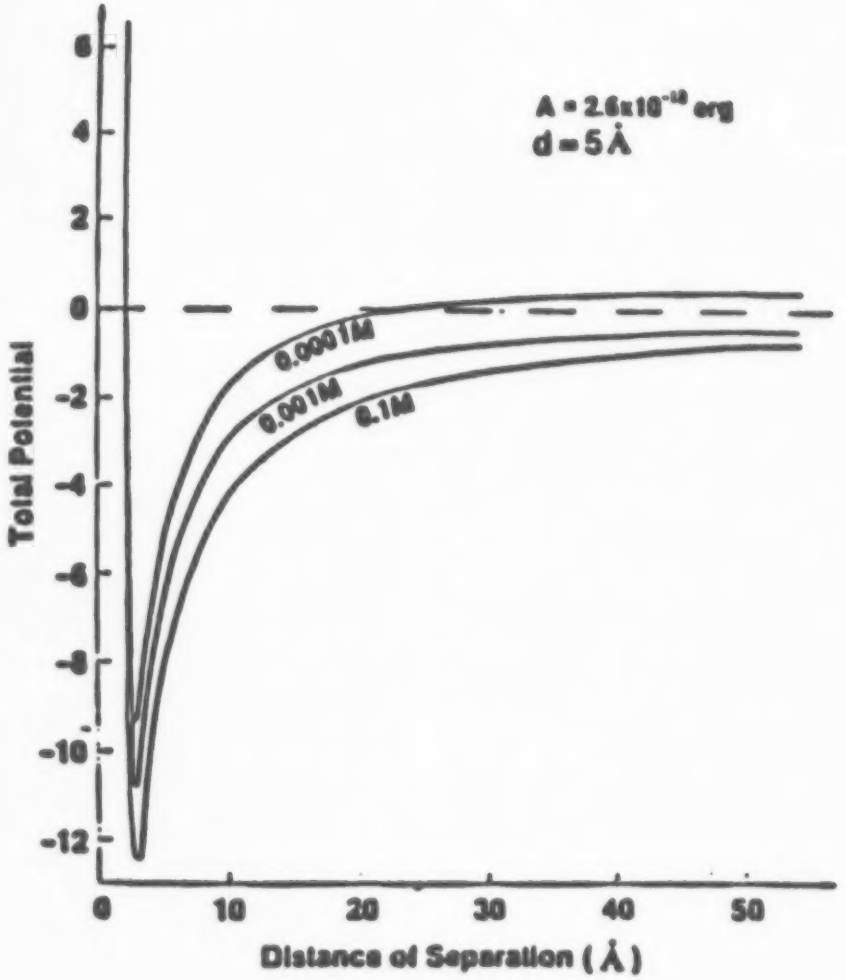


Figure 28: Total interaction potential as a function of distance of separation for calcium ions in solution (Reference 34)

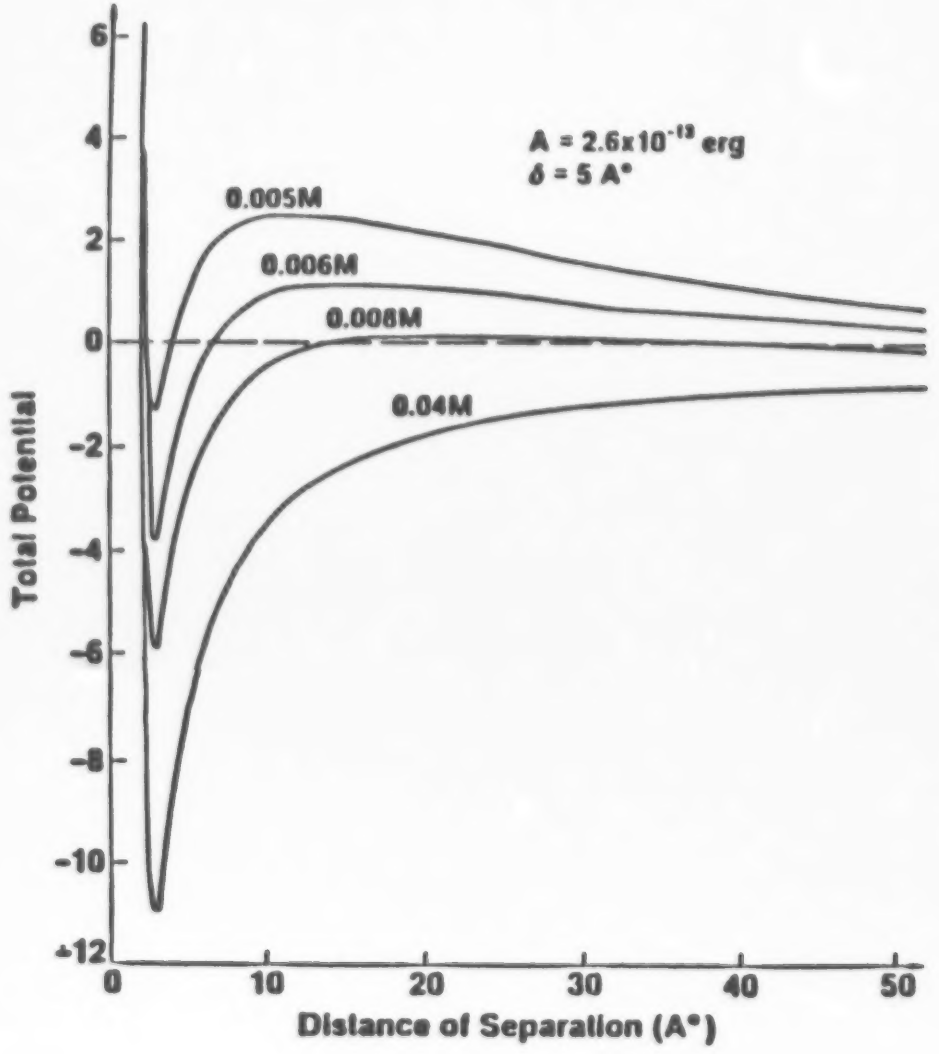


Figure 29: Total interaction potential as a function of distance of separation for sodium ions in solution
(Reference 34)

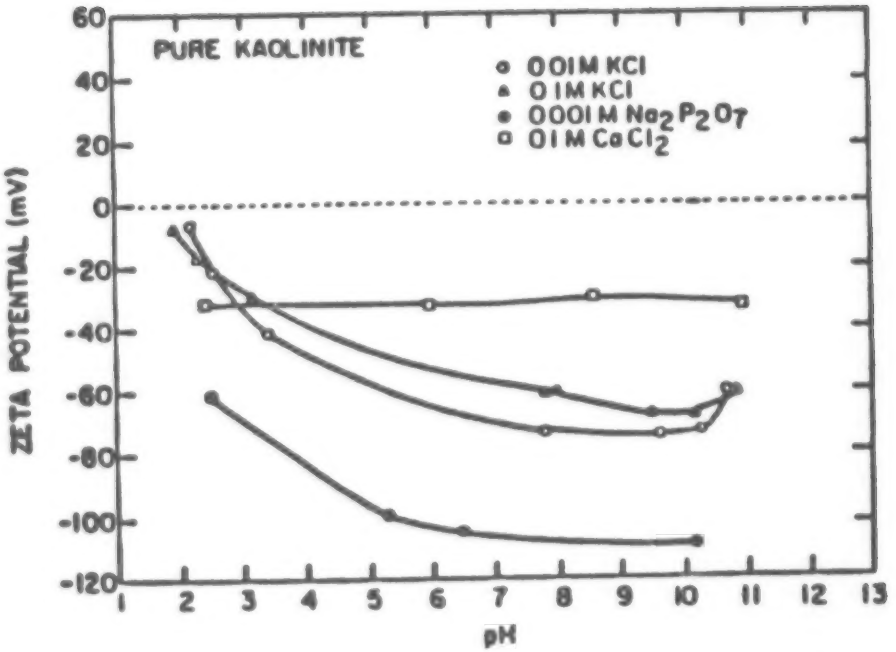


Figure 30: Zeta potential of kaolinite in the presence of polyvalent cations and anions

(Reference 5)

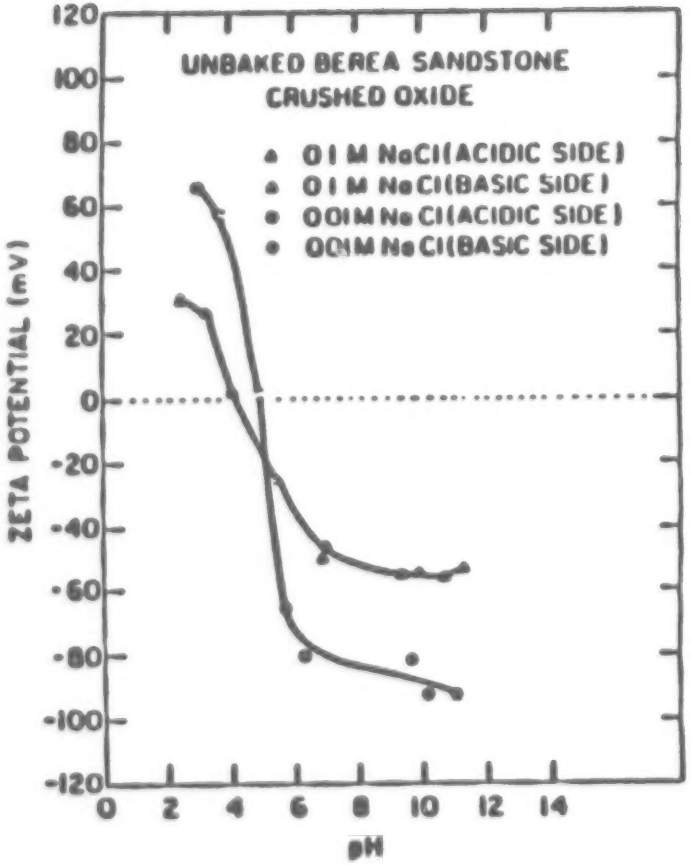


Figure 31: Zeta potential of detrital grains of Berea sandstone

(Reference 5)

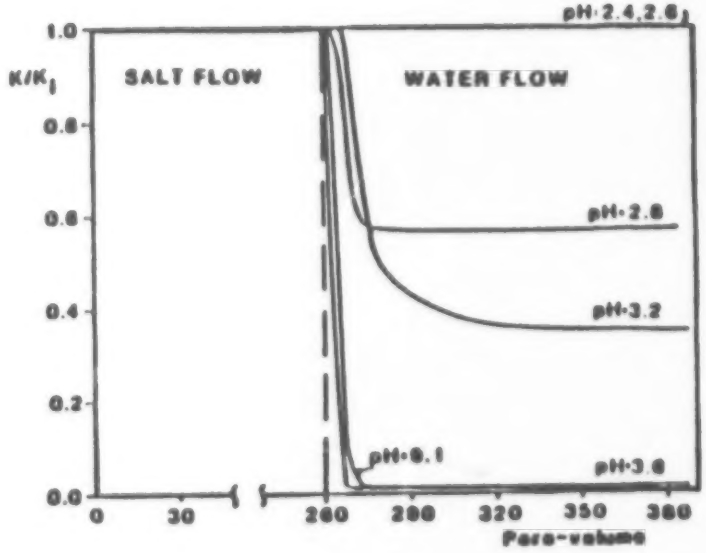


Figure 32: Variation of permeability with inlet pH

(Reference 71)

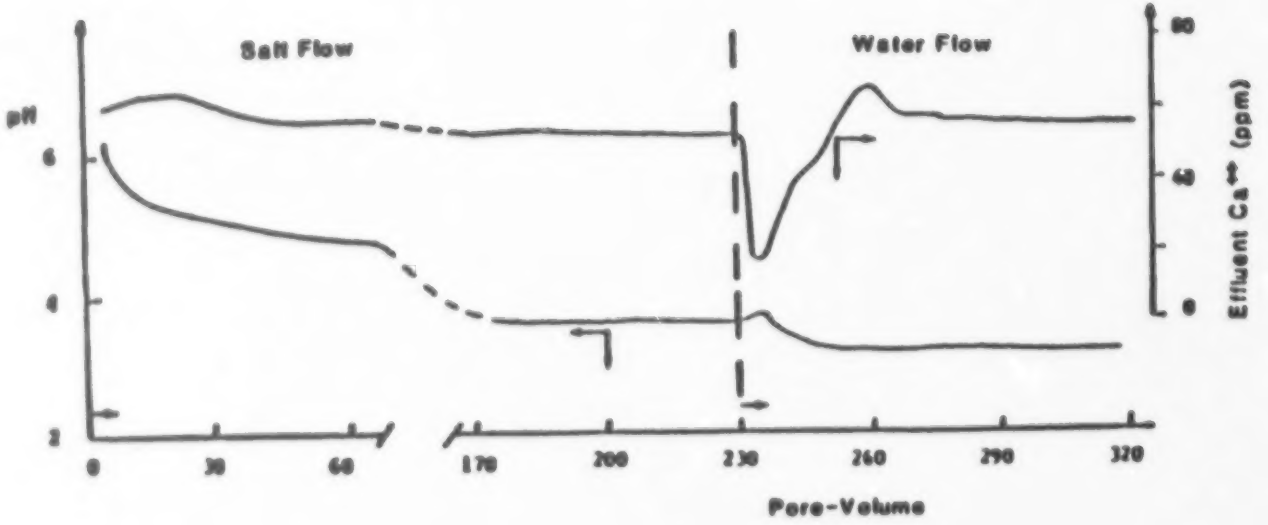


Figure 33: Effluent pH and calcium ion concentration for treatment at inlet pH of 2.4

(Reference 71)

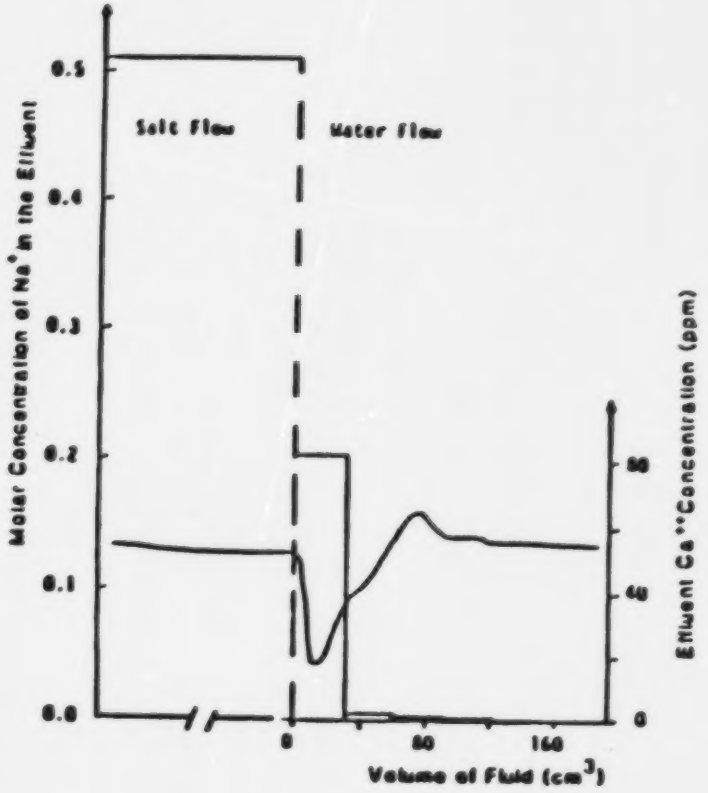


Figure 34: Variations of effluent calcium and sodium concentration for treatment at an inlet pH of 2.4

(Reference 71)

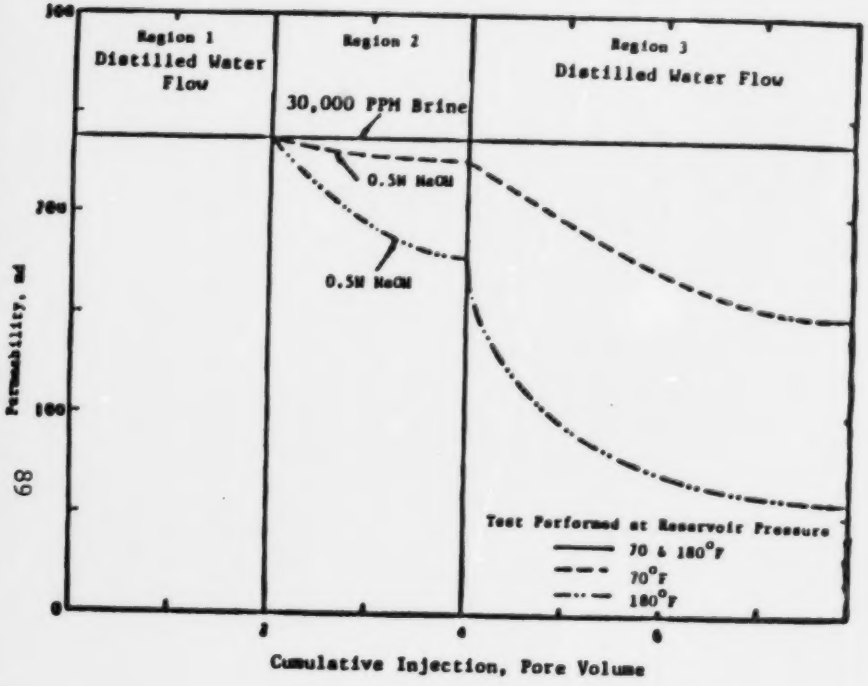


Figure 35: The effect of temperature on sensitivity of nonextracted cores

(Reference 18)

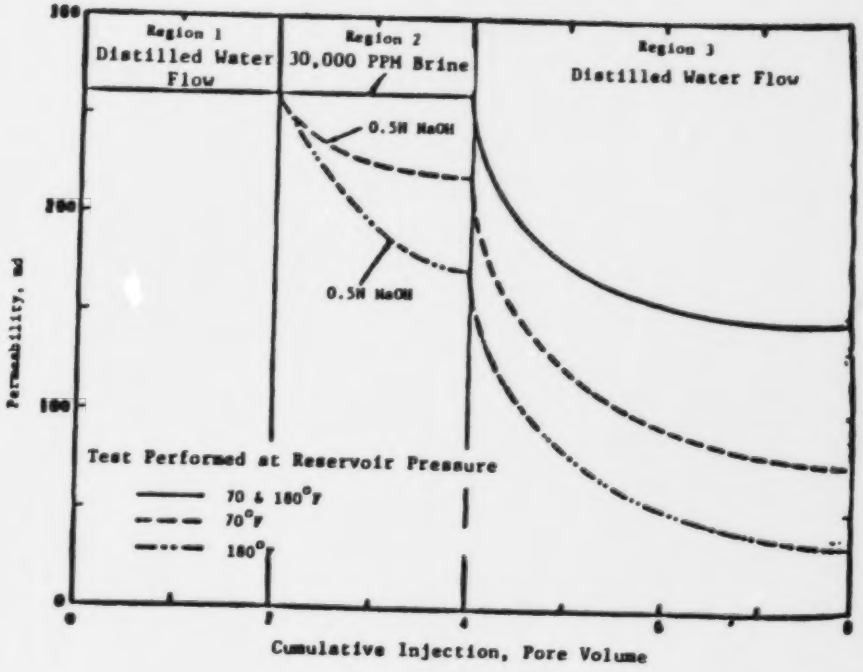


Figure 36: The effect of temperature on sensitivity of extracted cores

(Reference 18)

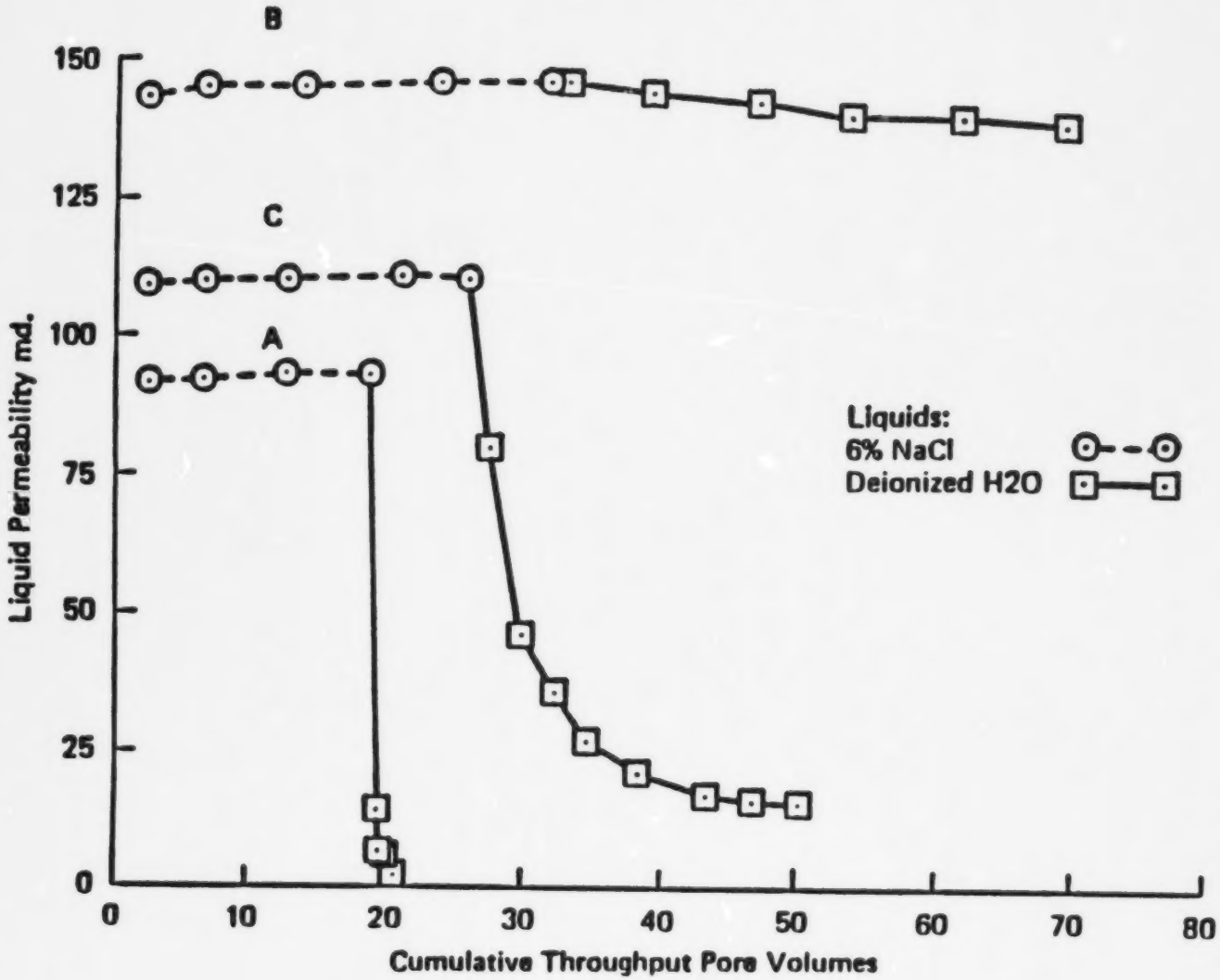


Figure 37: Water sensitivity of Berea sandstone (A), is eliminated by pretreatment by petroleum heavy ends (B). Removal of adsorbed layer restores water sensitivity (C)

(Reference 79)

Table 2

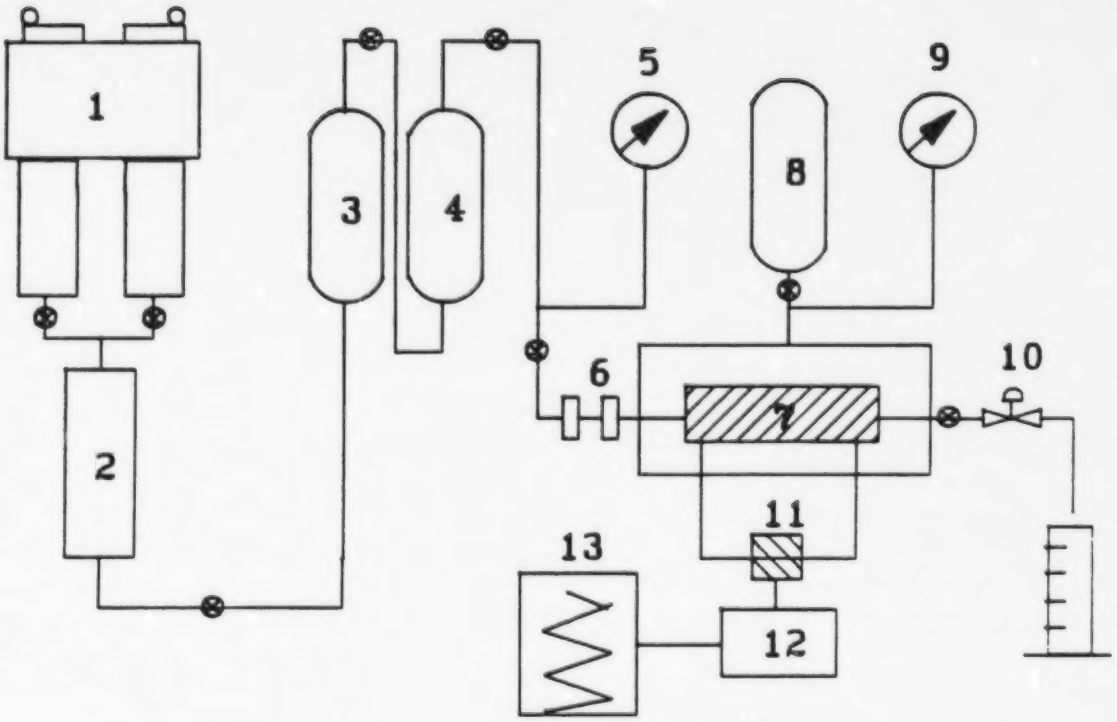
Composition of the Lindbergh Core

Mineral	Bulk Analysis	Fines Analysis
Quartz	85	9
Illite	2	3
Kaolinite	12	88
Feldspar	1	trace

Table 3

Results of Petrographic Image Analysis

NCP (kPa)	Mean Pore Size (microns)	Std. Deviation (microns)	Mean Pore Throat Size (microns)	Std.Deviation (microns)
1400	27.5	4.7	10.4	1.1
6900	26.1	3.2	10.2	1.8
20,700	22.3	4.2	9.4	1.7



1 Ruska pump
2 Flow multiplier
3 Methylene chloride container
4 Brine container
5 Upstream pressure
6 Balston filters
7 Core
8 Nitrogen supply
9 Overburden pressure
10 Back pressure regulator
11 Transducer
12 Demodulator
13 Chart recorder

FIGURE 38: **Schematic diagram of experimental set up**

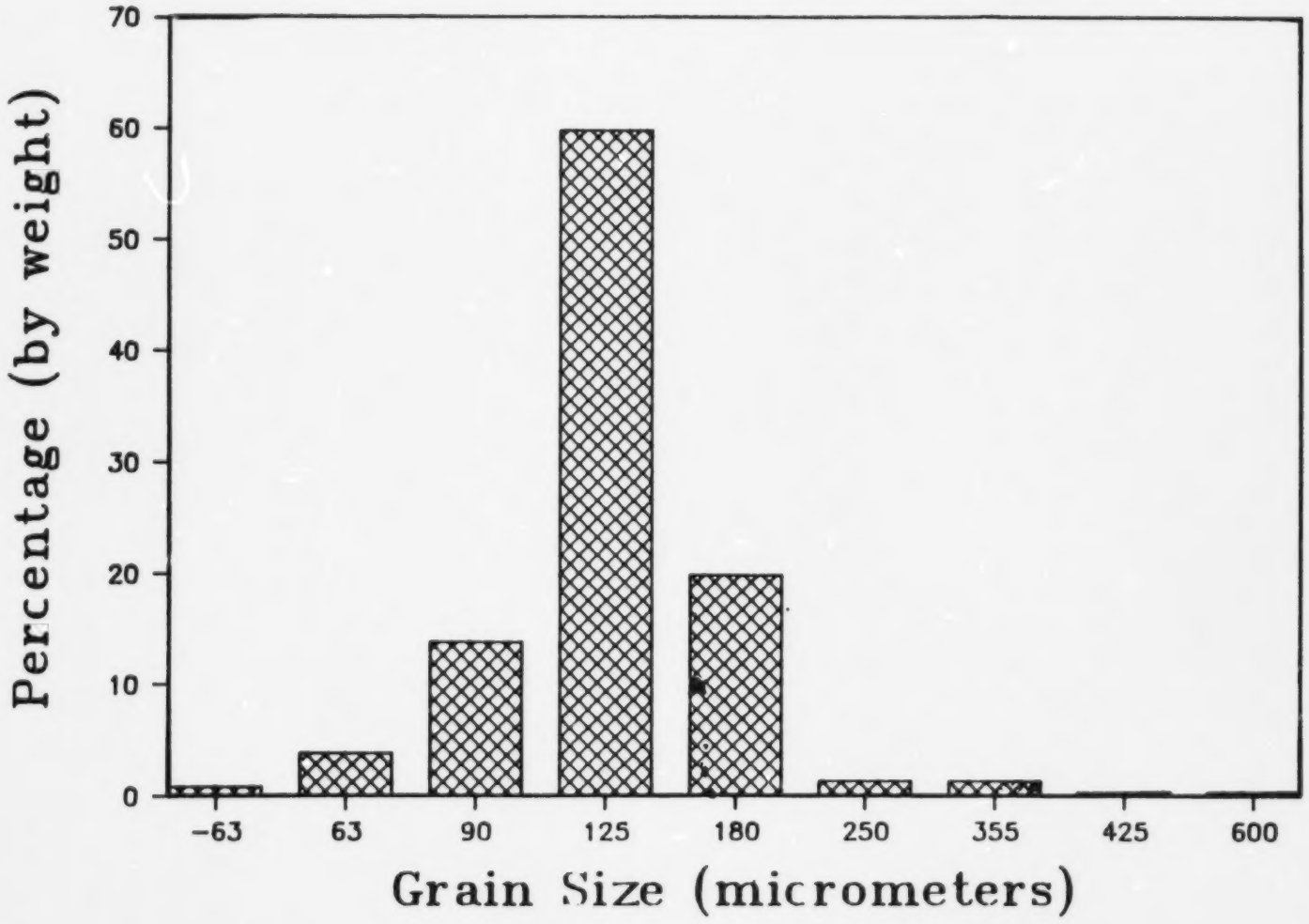


FIGURE 39: Lindbergh Sieve Analysis

Figure 40

Lindbergh SEM Photomicrographs

a. Low magnification photomicrograph (30X). Angularity of the grains and the abundant coating and pore fill consisting of fines can be seen

b. Higher magnification of the same sample (centre of the photo, 100X) showing further detail.

Figure 41

Lindbergh SEM Photomicrographs

a. Grain to fines relationship showing detrital clays (150X).

b. Moderate magnification (300X) of detrital clays showing non-distinct fines in the pore space.

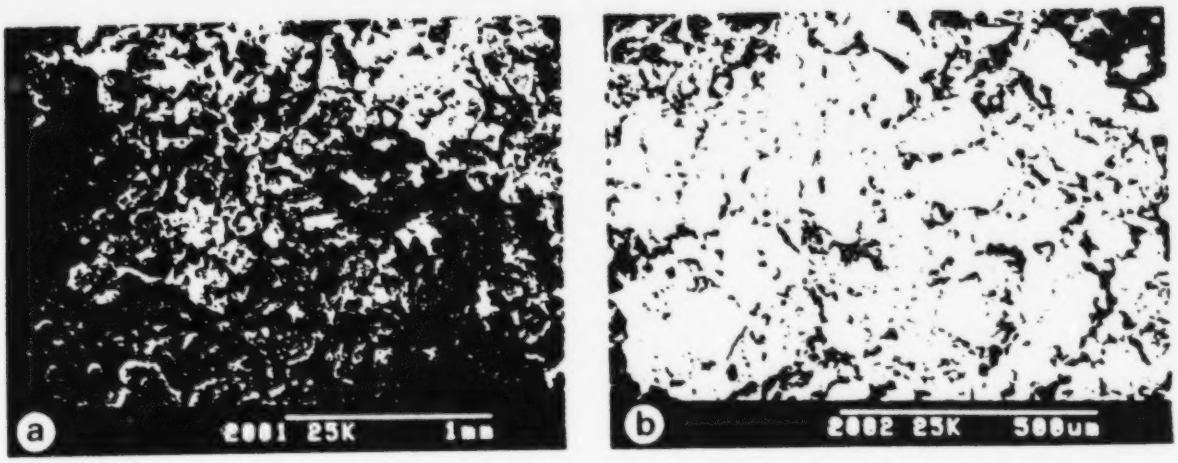


FIGURE 40

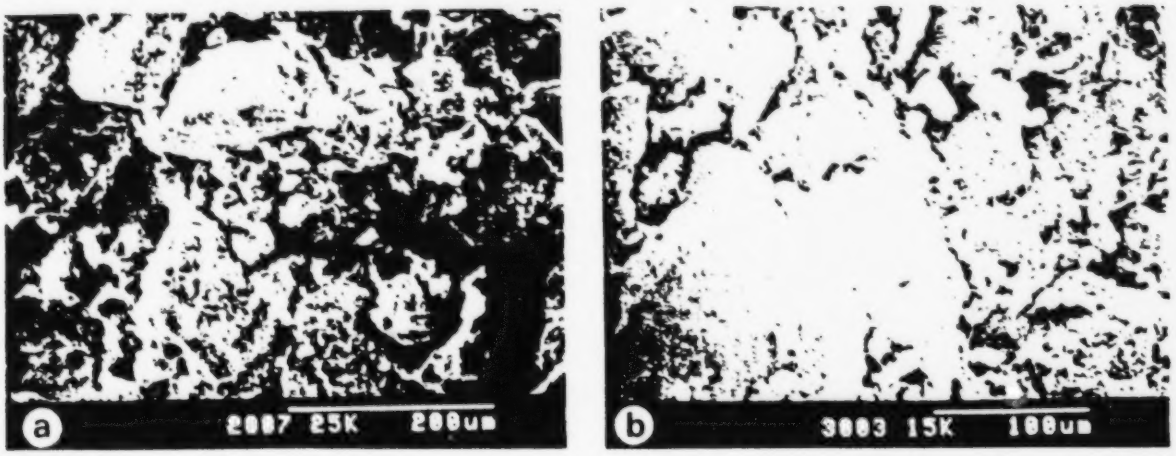


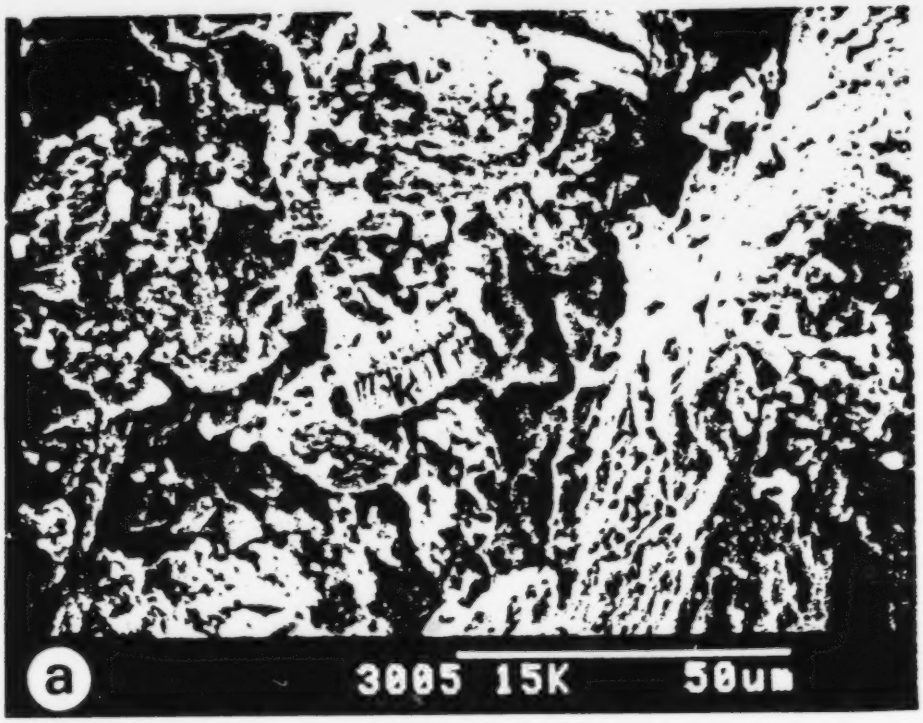
FIGURE 41

Figure 42

Lindbergh SEM Photomicrographs

a. Occasionally a well formed but eroded kaolinite booklet (k) is located in the sample (600X).

b. Higher magnification (2000X) of the kaolinite found in Figure 5a.



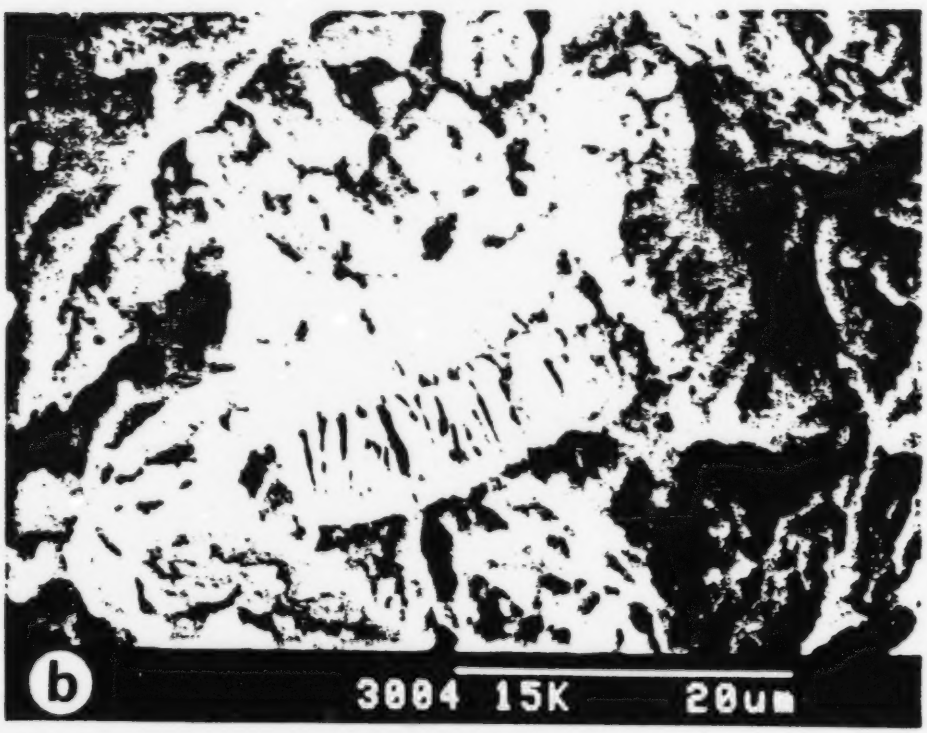


FIGURE 42

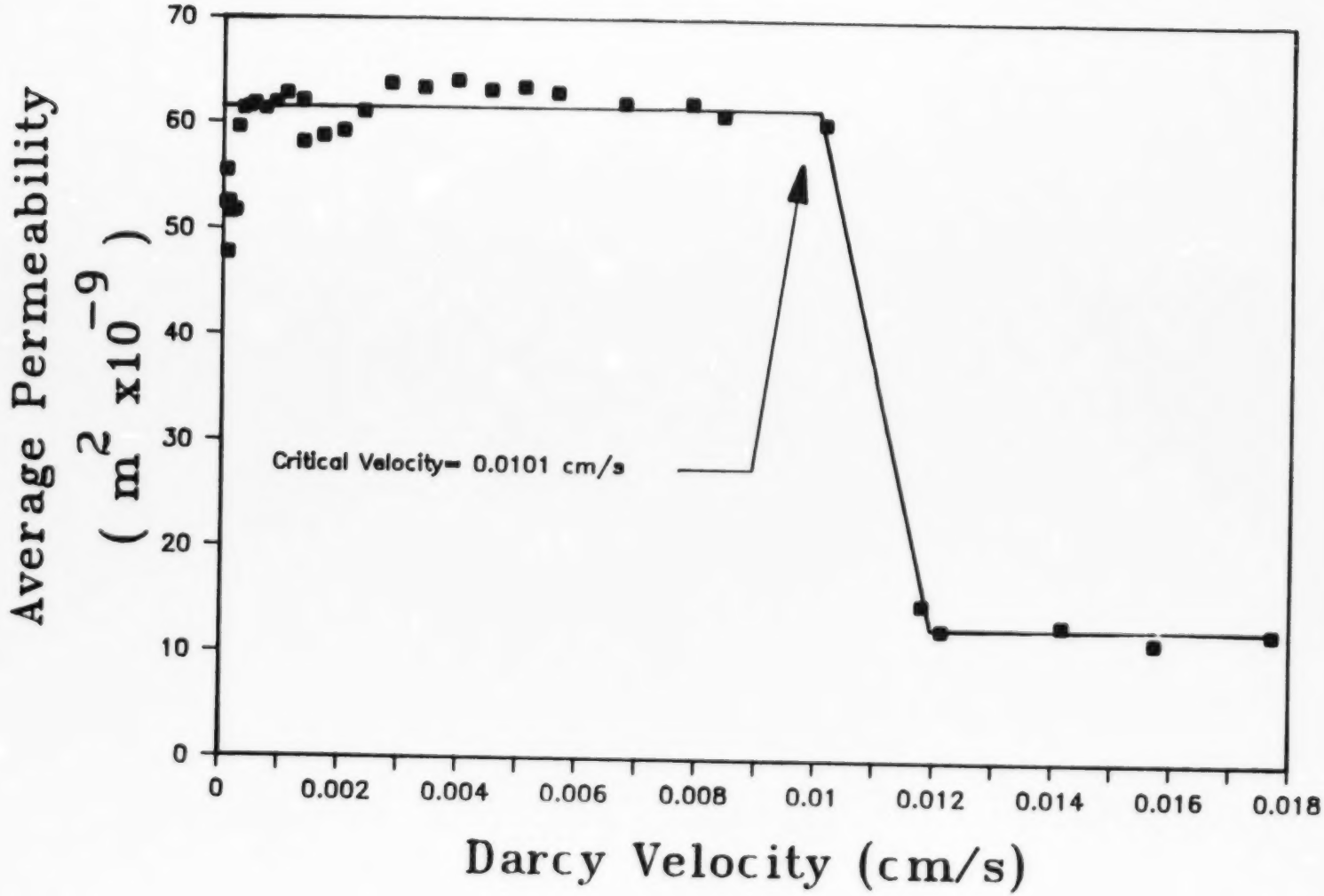


FIGURE 43 Critical Velocity Experiments at NCP=3447 kPa with Lindbergh Core

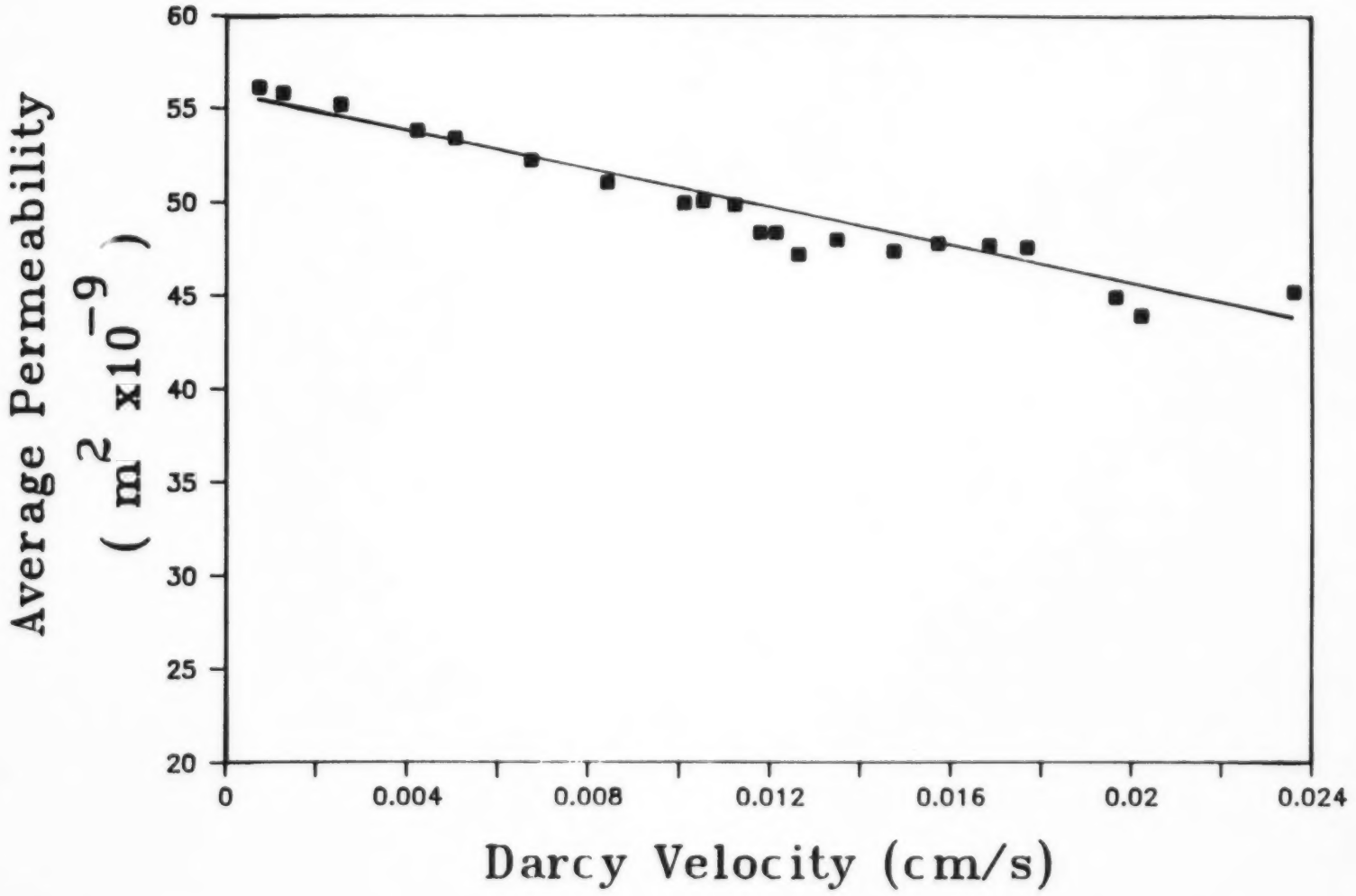


FIGURE 44 Critical Velocity Experiments at NCP=2068 kPa with Lindbergh Core

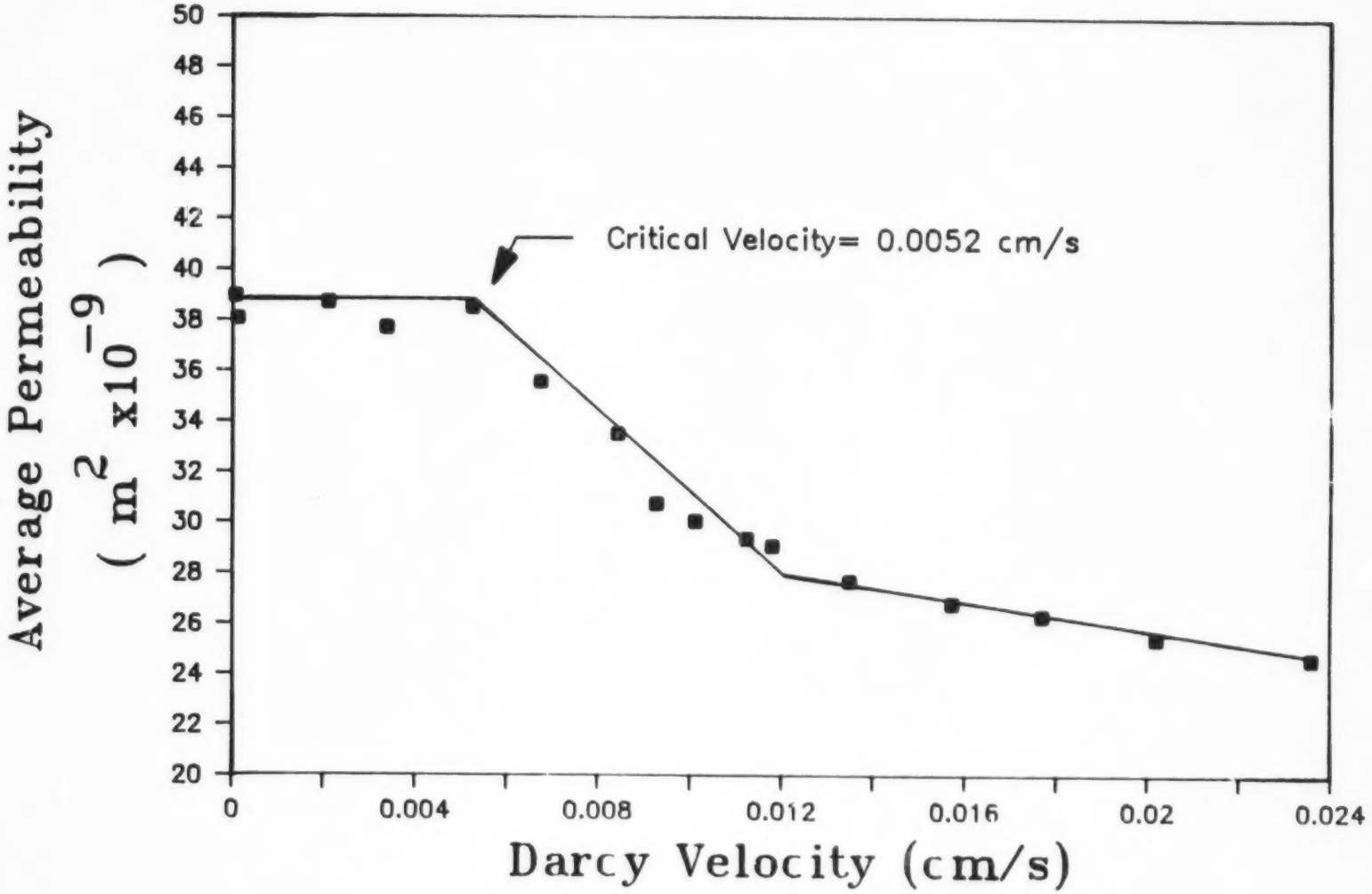


FIGURE 45 Critical Velocity Experiments at NCP=10,342 kPa with Lindbergh Core

Figure 46

Thin Section Photographs of Samples Confined at Various NCP's

a. Sample confined at 1400 kPa NCP.

b. Sample confined at 6900 kPa NCP.

c. Sample confined at 20,700 kPa NCP.

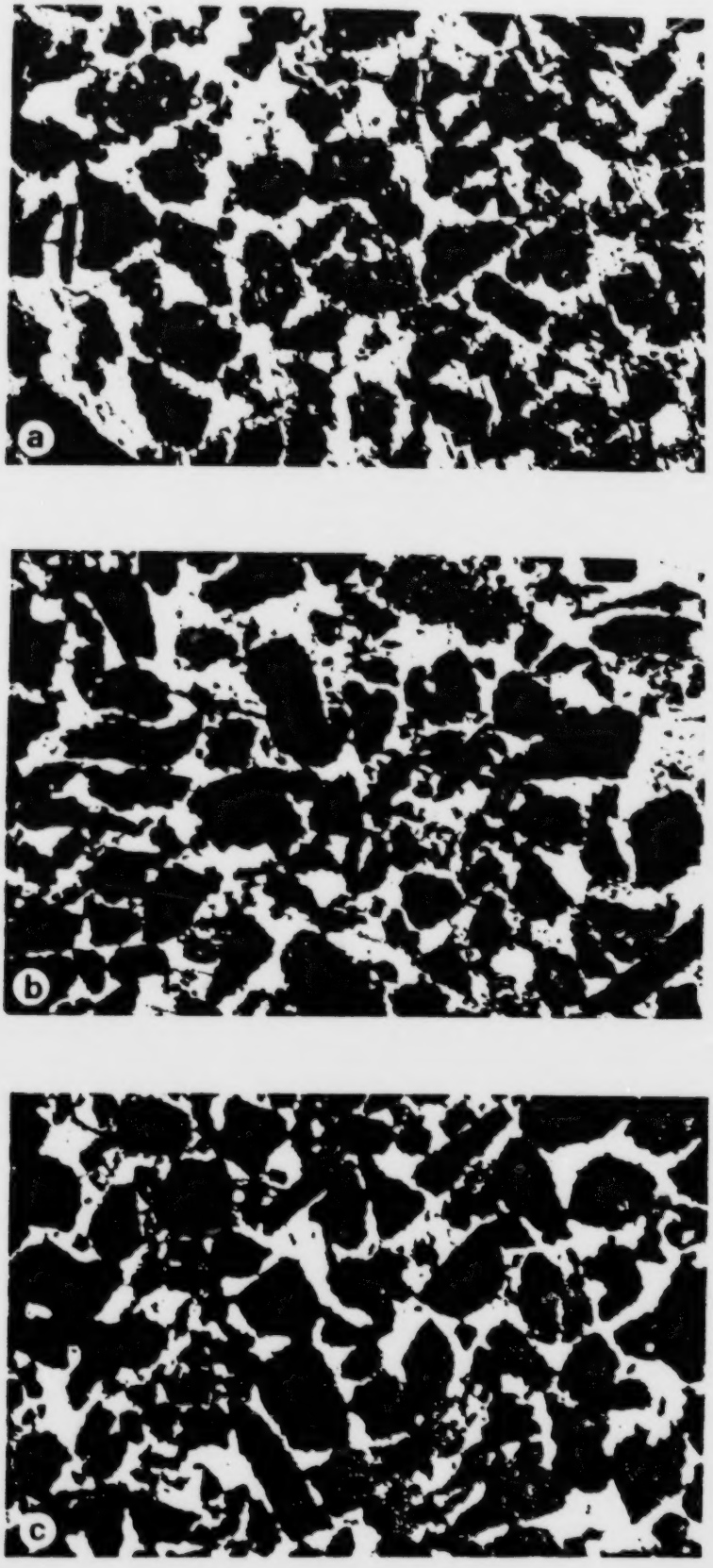


FIGURE 46

Figure 47

SEM Photomicrographs of Samples Confined at Various NCP's

a. Sample confined at 1400 kPa NCP.

b. Sample confined at 6900 kPa NCP.

c. Sample confined at 20,700 kPa NCP.

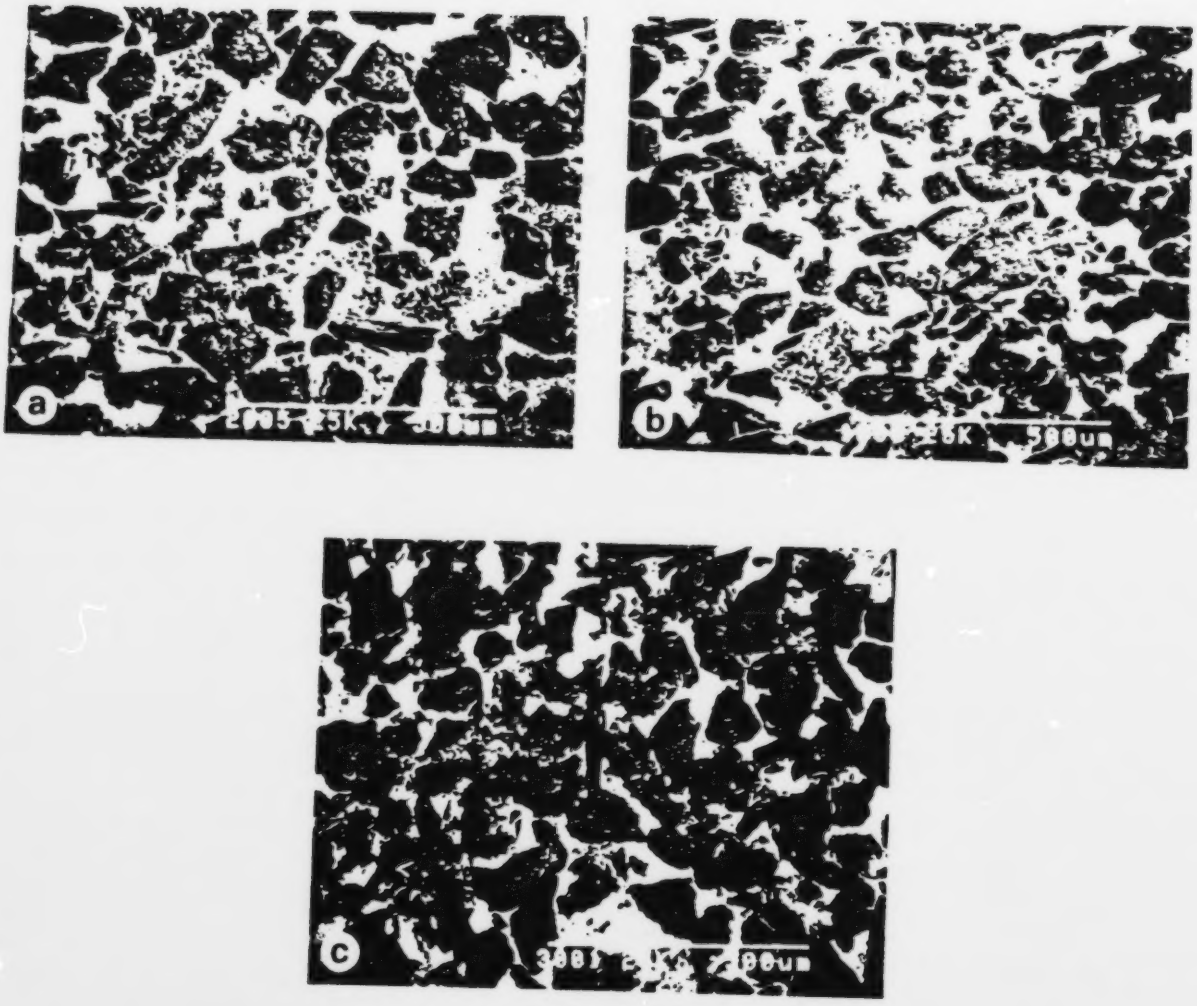


FIGURE 47

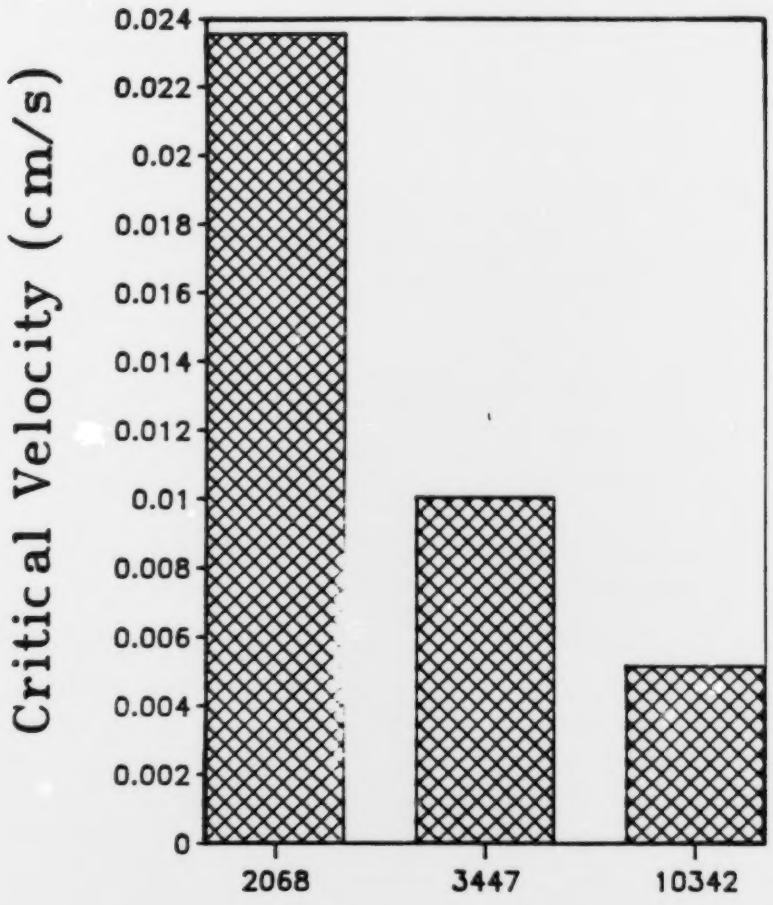


FIGURE 48 **Results from All Experiments**

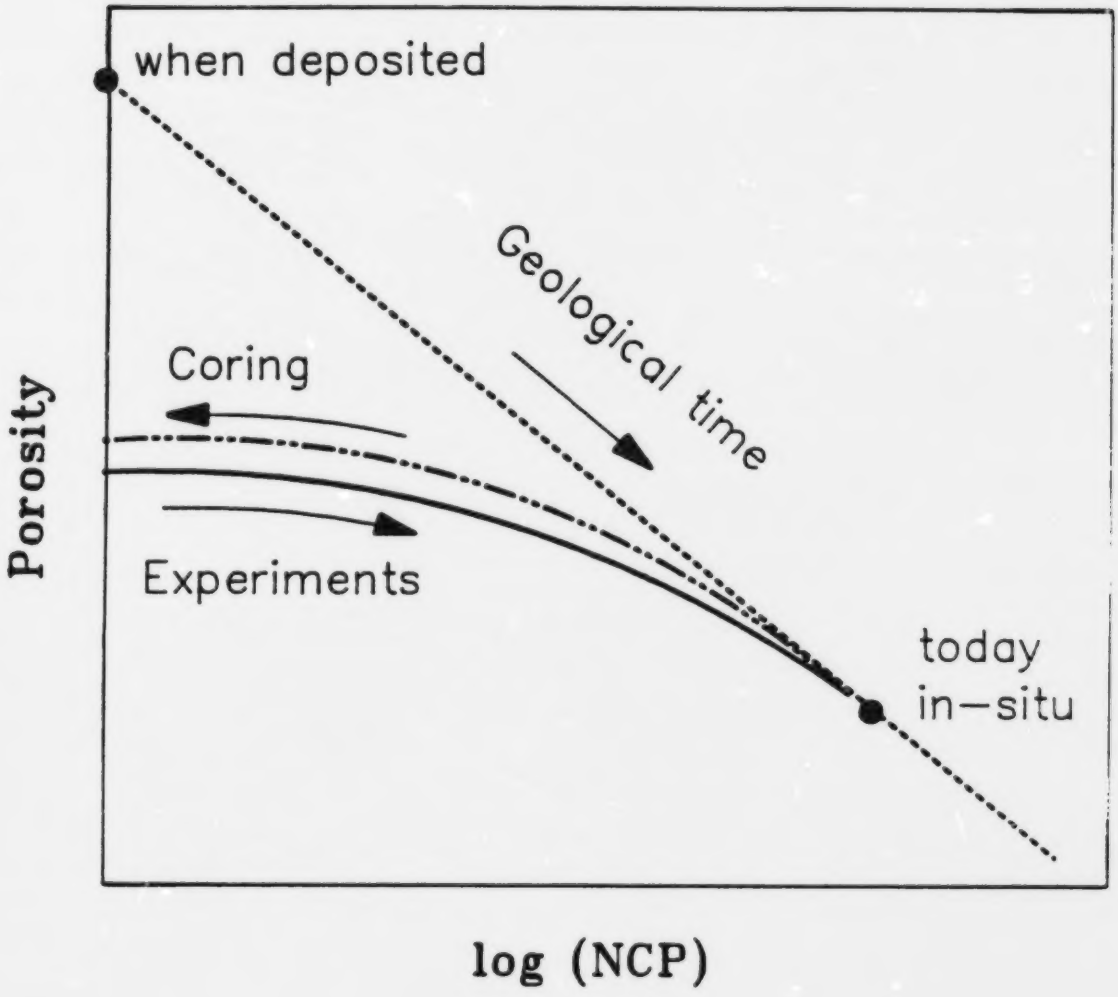


FIGURE 49 **Change in porosity with different processes in a heavy oil reservoir**

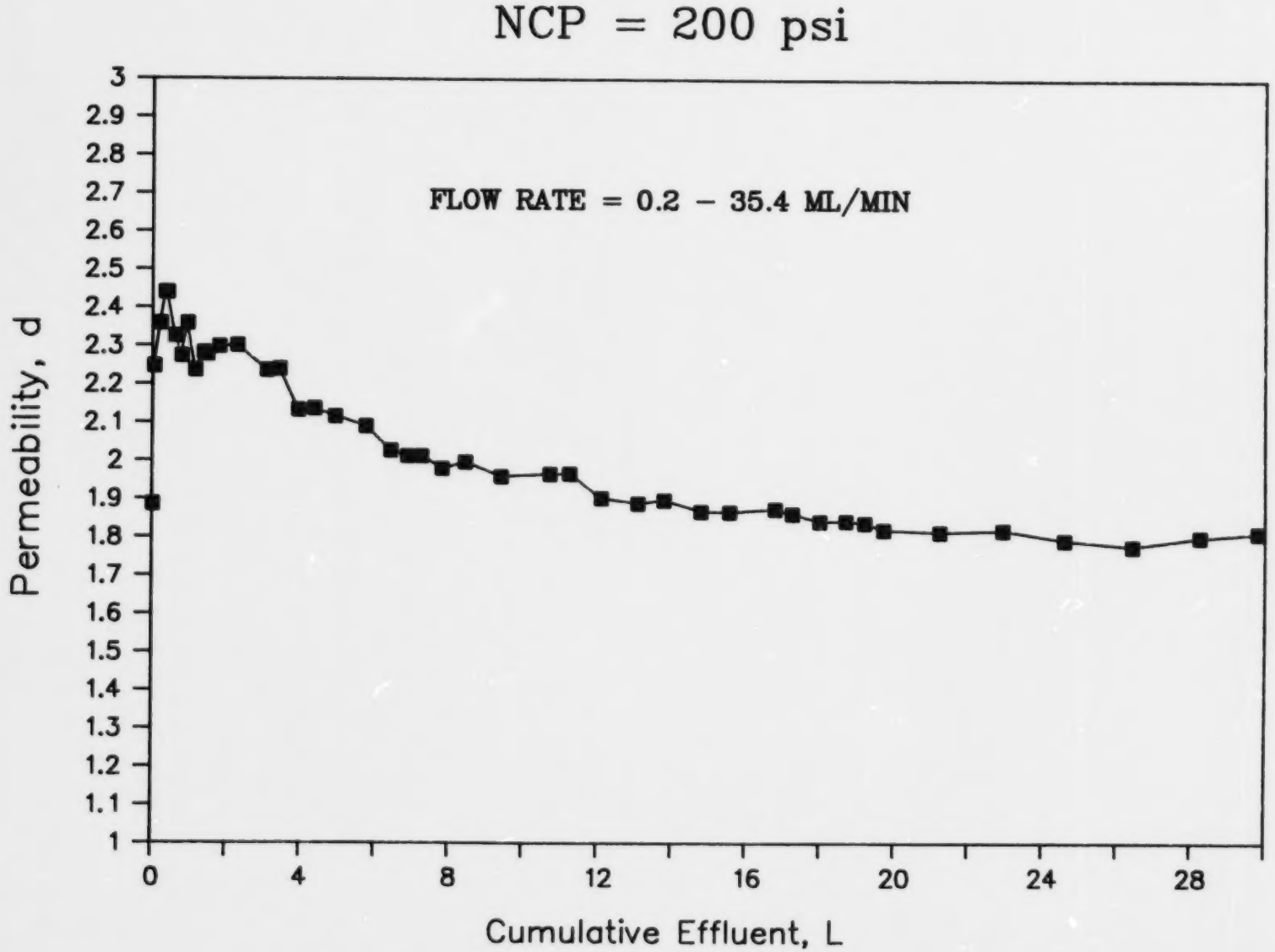


Figure 50: Effect of Velocity on Permeability of Frog-Lake McLaren Core - NCP = 200 psi.

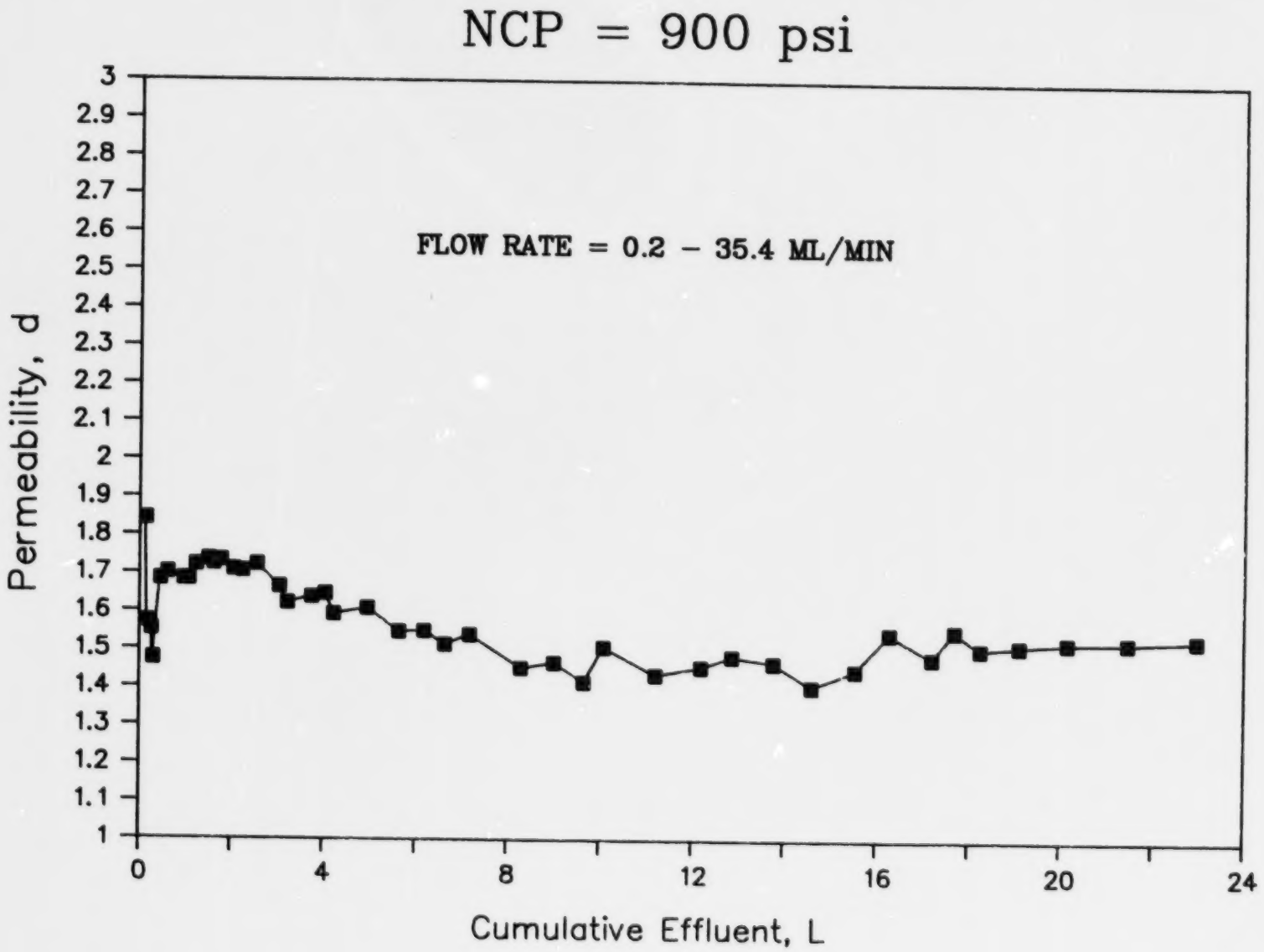


Figure 51: Effect of Velocity on Permeability of Frog-Lake McLaren Core - NCP - 900 psi

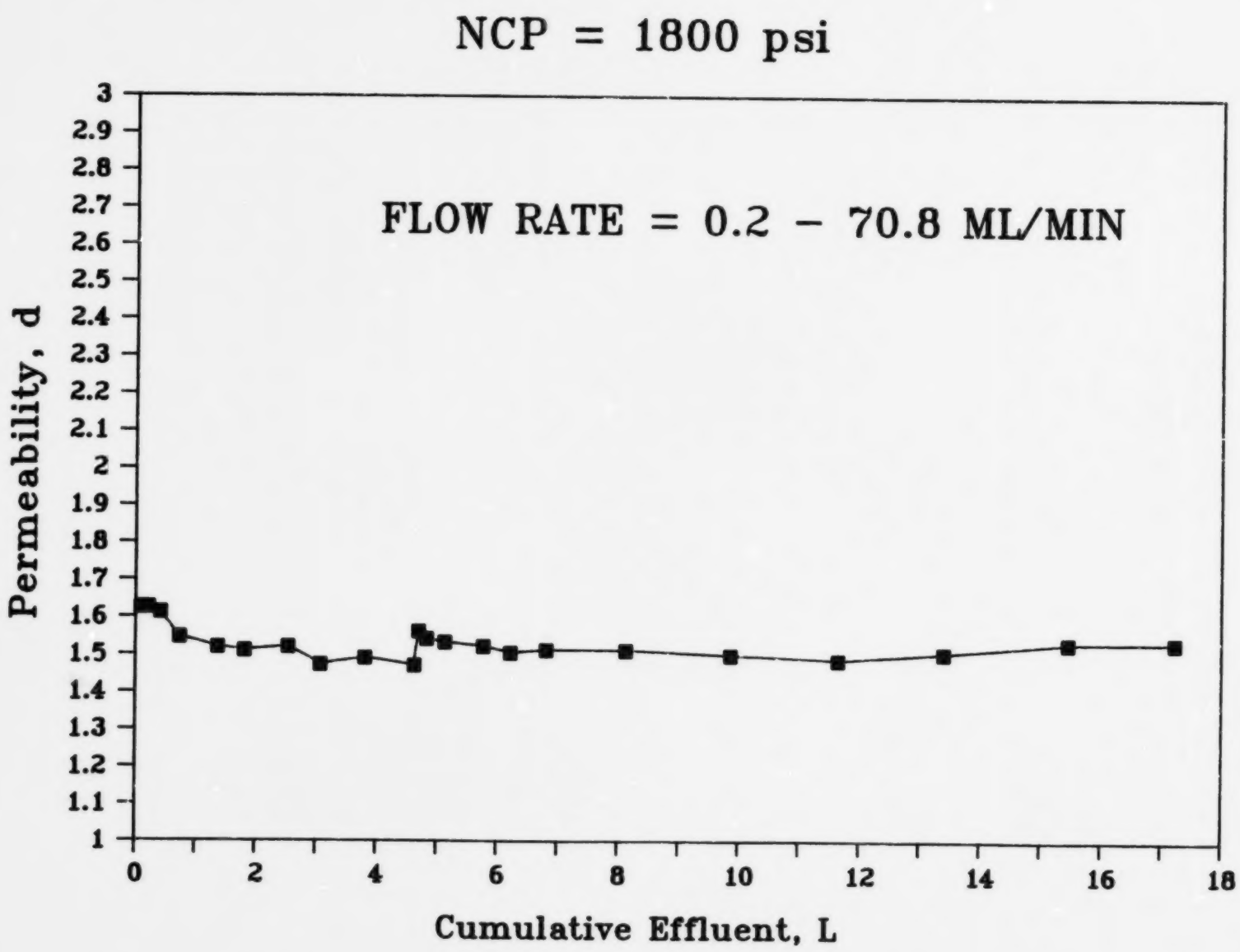


Figure 52: Effect of Velocity on Permeability of Frog-Lake McLaren Core - NCP = 1800 psi.

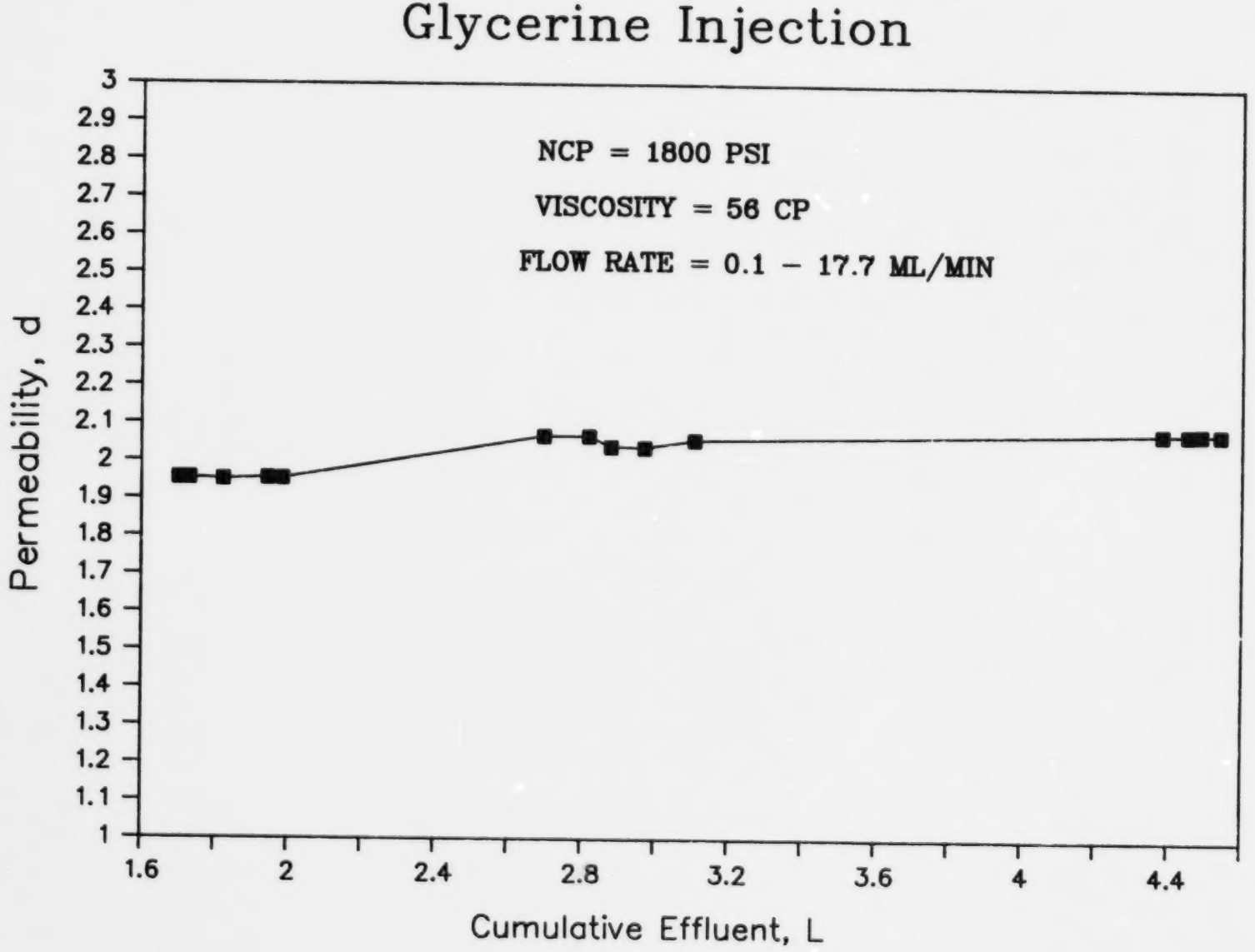


Figure 53: Effect of Fluid (Wetting) Viscosity on Permeability, Frog-Lake McLaren Core, NCP = 1800 psi.

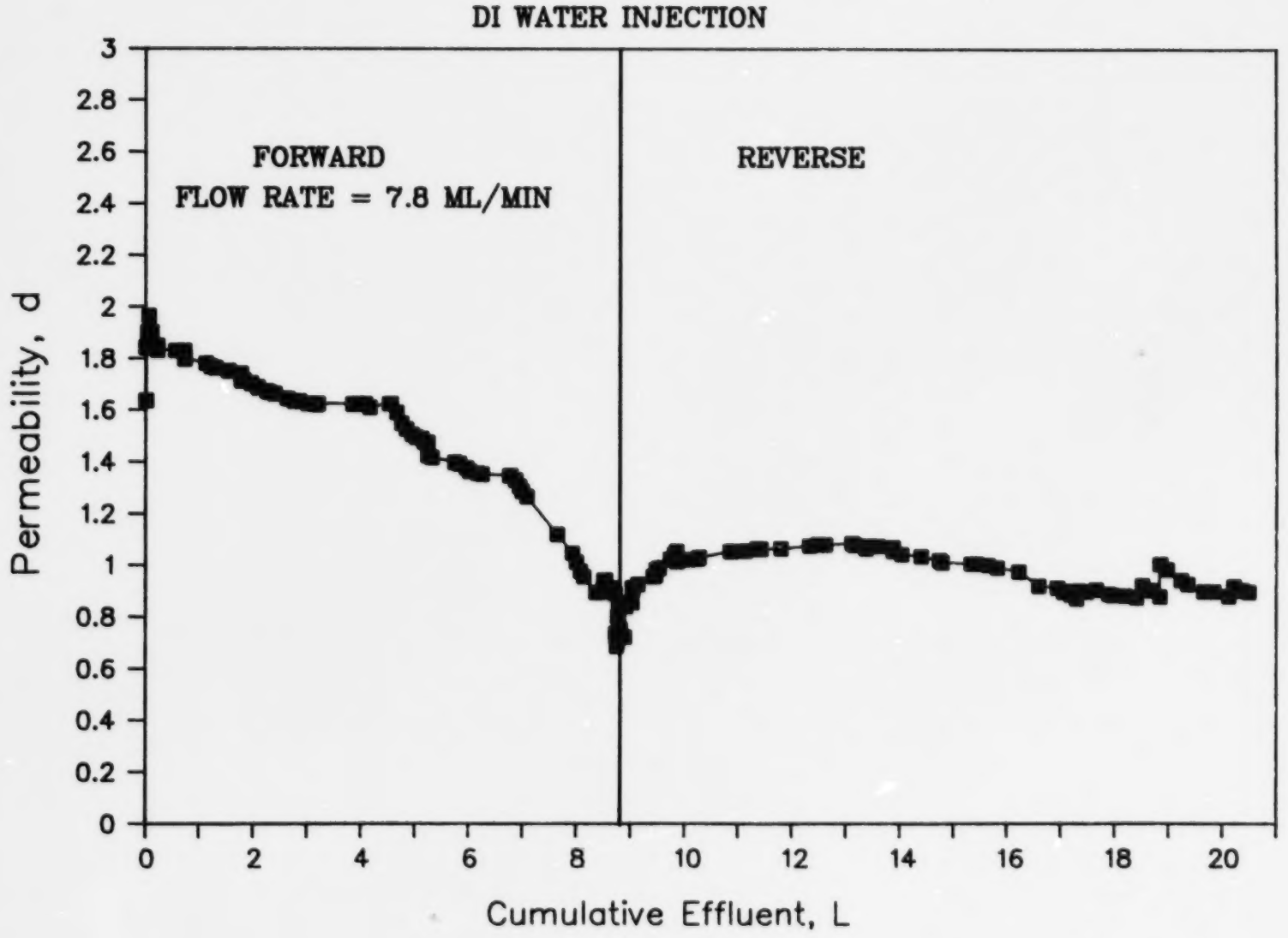


Figure 54: Water Sensitivity Test for Frog-Lake McLaren Core.

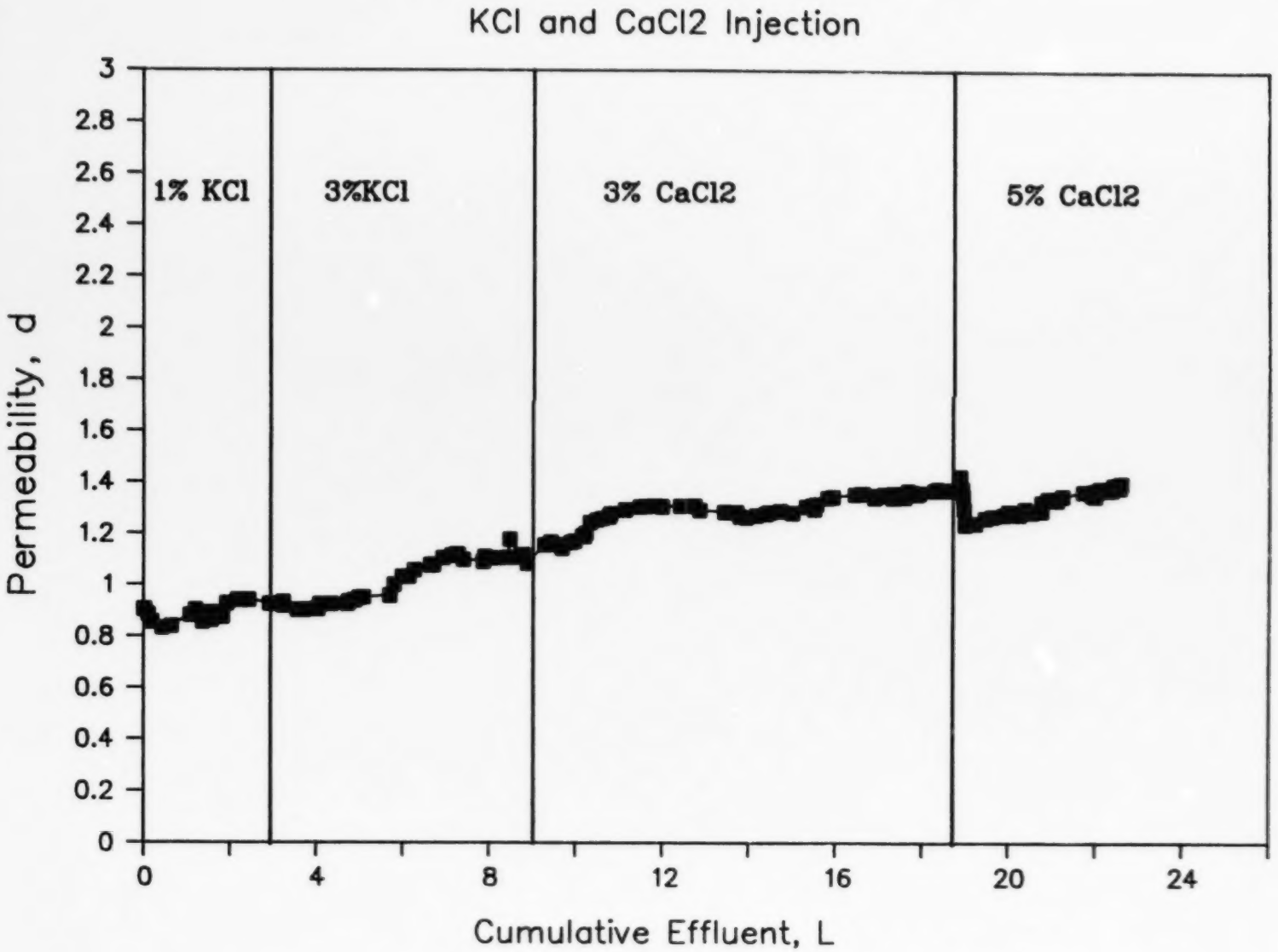


Figure 55: Effect of KCl and $CaCl_2$ on Permeability after De-ionized Water Chock

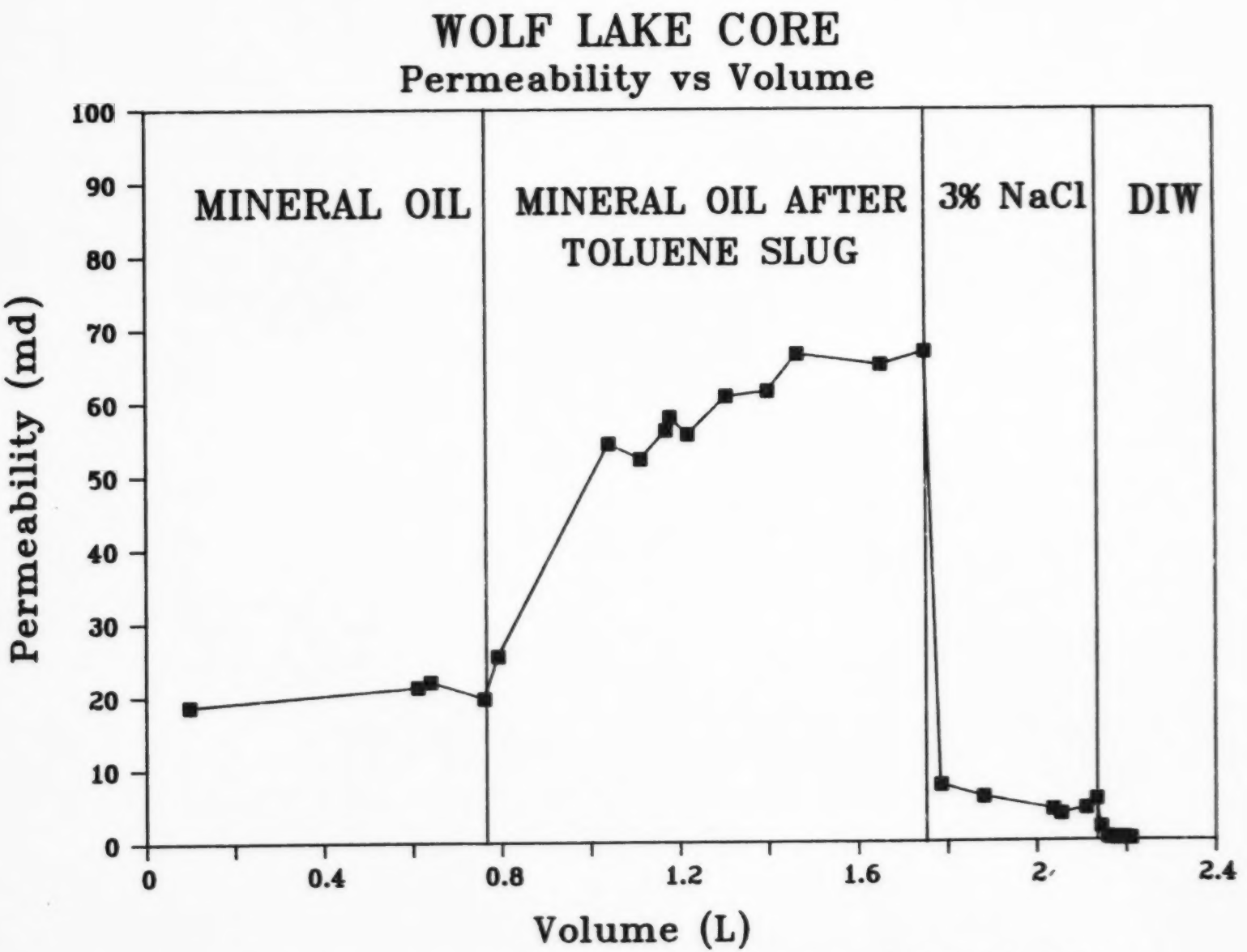


Figure 56: Effect of Injecting a Non-wetting Fluid on Permeability, Wolf-Lake Core, NCP = 1800 psi.